

1 Timothy M. Hogan (004567)  
Jennifer B. Anderson (015605)  
2 ARIZONA CENTER FOR LAW  
IN THE PUBLIC INTEREST  
3 514 W. Roosevelt Street  
Phoenix, Arizona 85003  
4 (602) 258-8850  
[thogan@aclpi.org](mailto:thogan@aclpi.org)  
5 [janderson@aclpi.org](mailto:janderson@aclpi.org)  
6 *Attorneys for Southwest Energy  
Efficiency Project*

7 Adam L. Stafford (025317)  
WESTERN RESOURCE ADVOCATES  
8 1429 N. 1st Street, Suite 100  
Phoenix, Arizona 85004  
9 (602) 562-9903  
[Adam.Stafford@westernresources.org](mailto:Adam.Stafford@westernresources.org)  
10 *Attorney for Western Resource Advocates*

11  
12 **BEFORE THE ARIZONA CORPORATION COMMISSION**

13 **COMMISSIONERS**

14 ROBERT "BOB" BURNS, Chairman  
15 BOYD W. DUNN  
16 SANDRA D. KENNEDY  
JUSTIN OLSON  
LEA MÁRQUEZ PETERSON

17 IN THE MATTER OF THE APPLICATION  
18 OF ARIZONA PUBLIC SERVICE  
COMPANY FOR A HEARING TO  
19 DETERMINE THE FAIR VALUE OF THE  
UTILITY VALUE OF THE COMPANY  
20 FOR RATEMAKING PURPOSES, TO FIX  
A JUST AND REASONABLE RATE OF  
21 RETURN THEREON, AND TO APPROVE  
RATE SCHEDULES DESIGNED TO  
22 DEVELOP SUCH RETURN.

Docket No. E-01345A-19-0236

**SOUTHWEST ENERGY EFFICIENCY  
PROJECT'S AND WESTERN  
RESOURCE ADVOCATES' NOTICE  
OF FILING DIRECT TESTIMONY OF  
BRENDON BAATZ  
(RATE DESIGN)**

23  
24 The Southwest Energy Efficiency Project ("SWEEP") and Western Resource  
25 Advocates ("WRA") hereby submit the redacted Direct Testimony (Rate Design) and exhibits  
26 of Brendon Baatz in the above-captioned docket.

1 The highly confidential version of Mr. Baatz' Direct Testimony is being provided under  
2 seal to the Commission and to Arizona Public Service ("APS"). Parties who have entered into  
3 the Protective Agreement will be able to view the confidential version of Mr. Baatz' testimony  
4 and exhibits by accessing the APS Rate Case website.

5 RESPECTFULLY SUBMITTED this 9th day of October 2020.

6 */s/ Jennifer Anderson*

7  
8 Timothy M. Hogan  
9 Jennifer B. Anderson  
10 ARIZONA CENTER FOR LAW IN THE  
11 PUBLIC INTEREST  
12 514 W. Roosevelt Street  
13 Phoenix, AZ 85003  
14 *Attorneys for Southwest Energy Efficiency*  
15 *Project*

16 */s/ Adam Stafford*

17  
18 Adam L. Stafford  
19 WESTERN RESOURCE ADVOCATES  
20 1429 N. 1st Street, Suite 100  
21 Phoenix, Arizona 85004  
22 *Attorney for Western Resource Advocates*

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Phoenix, Arizona

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9th day of October, 2020 to:

Albert H Acken  
DICKINSON WRIGHT PLLC  
1850 N Central Ave., Suite 1400  
Phoenix AZ 85004  
[aacken@dickinson-wright.com](mailto:aacken@dickinson-wright.com)

Armando Nava  
The Nava Law Firm PLLC  
1641 E Osborn Rd Ste 8  
Phoenix AZ 85016  
[Filings@navalawaz.com](mailto:Filings@navalawaz.com)

Court Rich  
Rose Law Group PC  
7144 E Stetson Drive Suite 300  
Scottsdale AZ 85251  
[CRich@RoseLawGroup.com](mailto:CRich@RoseLawGroup.com)

Daniel Pozefsky  
RUCO  
1110 West Washington, Suite 220  
Phoenix AZ 85007  
[jfuentes@azruco.gov](mailto:jfuentes@azruco.gov)  
[procedural@azruco.gov](mailto:procedural@azruco.gov)  
[rdelafuente@azruco.gov](mailto:rdelafuente@azruco.gov)  
[dpozefsky@azruco.gov](mailto:dpozefsky@azruco.gov)

David Bender  
EARTHJUSTICE  
1001 G Street, NW, Suite 1000  
Washington DC 20001  
[dbender@earthjustice.org](mailto:dbender@earthjustice.org)

Garry Hays  
Law Office of Garry Hays PC  
2198 E Camelback Rd Suite 230  
Phoenix AZ 85016  
[Ghays@lawgdh.com](mailto:Ghays@lawgdh.com)

1 Giancarlo Estrada  
2 KAMPER ESTRADA, LLP  
3 3030 N. 3rd Street, Suite 770  
4 Phoenix AZ 85012  
[gestrada@lawphx.com](mailto:gestrada@lawphx.com)

5 Greg Patterson  
6 Munger Chadwick/Competitive Power Alliance  
7 5511 S. Jolly Roger  
8 Tempe AZ 85283  
[Greg@azcpa.org](mailto:Greg@azcpa.org)

9 Gregory M. Adams  
10 515 N. 27th St.  
11 Boise ID 83702  
[greg@richardsonadams.com](mailto:greg@richardsonadams.com)  
[greg.bass@calpinesolutions.com](mailto:greg.bass@calpinesolutions.com)

12 Holly L. Buchanan  
13 139 Barnes Dr., Suite 1  
14 Tyndall AFB FL 32403  
[Holly.buchanan.1@us.af.mil](mailto:Holly.buchanan.1@us.af.mil)

15 Jason Y. Moyes  
16 Moyes Sellers & Hendricks  
17 1850 N. Central Ave., Ste. 1100  
18 Phoenix AZ 85004  
[jim@harcuvar.com](mailto:jim@harcuvar.com)  
[jasonmoyes@law-msh.com](mailto:jasonmoyes@law-msh.com)  
[jjw@krsaline.com](mailto:jjw@krsaline.com)

19  
20 Jason R. Mullis  
21 WOOD SMITH BENNING & BERMAN LLP  
22 2525 E. Camelback Road, Ste. 450  
23 Phoenix AZ 85016  
[greg@richardsonadams.com](mailto:greg@richardsonadams.com)  
[jmullis@wshblaw.com](mailto:jmullis@wshblaw.com)  
[greg.bass@calpinesolutions.com](mailto:greg.bass@calpinesolutions.com)

1 John B. Coffman  
2 JOHN B. COFFMAN LLC  
3 871 Tuxedo Blvd.  
4 St. Louis MO 63119  
[john@johncoffman.net](mailto:john@johncoffman.net)

5 John S. Thornton  
6 8008 N. Invergordon Rd.  
7 Paradise Valley AZ 85253  
[john@thorntonfinancial.org](mailto:john@thorntonfinancial.org)

8 Jonathan Jones  
9 14324 N 160th Dr.  
10 Surprise AZ 85379  
[jones.2792@gmail.com](mailto:jones.2792@gmail.com)

11 Karen S White  
12 AFIMSC/JAQ  
13 139 Barnes Ave.  
14 Tyndall AFB FL 32403  
[karen.white.13@us.af.mil](mailto:karen.white.13@us.af.mil)

15 Kimberly A. Dutcher  
16 NAVAJO NATION DEPARTMENT OF  
17 JUSTICE  
18 P.O. Box 2010  
19 Window Rock AZ 86515  
[kdutcher@nndoj.org](mailto:kdutcher@nndoj.org)  
[aquinn@nndoj.org](mailto:aquinn@nndoj.org)

20 Kurt J. Boehm  
21 Boehm, Kurtz & Lowry  
22 36 E. Seventh St. Suite 1510  
23 Cincinnati OH 45202  
[jkylercohn@BKLawfirm.com](mailto:jkylercohn@BKLawfirm.com)  
[kboehm@bkllawfirm.com](mailto:kboehm@bkllawfirm.com)

1 MAJ Scott L Kirk  
2 AFLOA/JACE-ULFSC  
3 139 Barnes Dr., Suite 1  
4 Tyndall AFB FL 32403-5317  
5 [scott.kirk.2@us.af.mil](mailto:scott.kirk.2@us.af.mil)

6 Marta Darby  
7 Earthjustice  
8 633 17th Street Suite 1600  
9 Denver CO 80202  
10 [mdarby@earthjustice.org](mailto:mdarby@earthjustice.org)

11 Melissa M. Krueger  
12 Pinnacle West Capital Corporation  
13 400 North 5th Street, MS 8695  
14 Phoenix AZ 85004  
15 [Andrew.Schroeder@aps.com](mailto:Andrew.Schroeder@aps.com)  
[rodney.ross@aps.com](mailto:rodney.ross@aps.com)  
[Thomas.Mumaw@pinnaclewest.com](mailto:Thomas.Mumaw@pinnaclewest.com)  
[Theresa.Dwyer@pinnaclewest.com](mailto:Theresa.Dwyer@pinnaclewest.com)  
[ratecase@aps.com](mailto:ratecase@aps.com)  
[Leland.Snook@aps.com](mailto:Leland.Snook@aps.com)  
[Melissa.Krueger@pinnaclewest.com](mailto:Melissa.Krueger@pinnaclewest.com)

16 Nicholas J. Enoch  
17 LUBIN & ENOCH, PC  
18 349 N. Fourth Ave.  
19 Phoenix AZ 85003  
20 [bruce@lubinandenoch.com](mailto:bruce@lubinandenoch.com)  
[clara@lubinandenoch.com](mailto:clara@lubinandenoch.com)  
[nick@lubinandenoch.com](mailto:nick@lubinandenoch.com)

21 Patricia Madison  
22 13345 W. Evans Drive  
23 Surprise AZ 85379  
24 [Patricia\\_57@q.com](mailto:Patricia_57@q.com)  
25  
26

1 Patrick J. Black  
2 FENNEMORE CRAIG, P.C.  
3 2394 E. Camelback Rd. Suite 600  
4 Phoenix AZ 85016  
5 [lferrigni@fclaw.com](mailto:lferrigni@fclaw.com)  
6 [pblack@fclaw.com](mailto:pblack@fclaw.com)

7 Richard Gayer  
8 526 W. Wilshire Dr.  
9 Phoenix AZ 85003  
10 [rgayer@cox.net](mailto:rgayer@cox.net)

11 Robert A Miller  
12 12817 W. Ballad Drive  
13 Sun City West AZ 85378-5375  
14 [rdjscw@gmail.com](mailto:rdjscw@gmail.com)  
15 [Bob.miller@porascw.org](mailto:Bob.miller@porascw.org)

16 Robin Mitchell  
17 Arizona Corporation Commission Director &  
18 Chief Counsel - Legal Division  
19 1200 West Washington St.  
20 Phoenix AZ 85007  
21 [legaldiv@azcc.gov](mailto:legaldiv@azcc.gov)  
22 [utildivservicebyemail@azcc.gov](mailto:utildivservicebyemail@azcc.gov)

23 Scott S. Wakefield  
24 HIENTON CURRY, P.L.L.C.  
25 5045 N 12th Street, Suite 110  
26 Phoenix AZ 85014-3302  
[Stephen.Chriss@walmart.com](mailto:Stephen.Chriss@walmart.com)  
[swakefield@hclawgroup.com](mailto:swakefield@hclawgroup.com)

Shelly A. Kaner  
8831 W. Athens St.  
Peoria AZ 85382

1 Thomas Harris Distributed Energy Resource  
2 Association (DERA)  
3 5215 E. Orchid Ln  
4 Paradise Valley AZ 85253  
[Thomas.Harris@DERA-AZ.org](mailto:Thomas.Harris@DERA-AZ.org)

5 Thomas A. Jernigan  
6 AFIMSC/JAU  
7 139 Barnes Drive, Suite 1  
8 Tyndall AFB FL 32403-5317  
[thomas.jernigan.3@us.af.mil](mailto:thomas.jernigan.3@us.af.mil)

9 Timothy M. Hogan  
10 ARIZONA CENTER FOR LAW IN THE  
11 PUBLIC INTEREST  
12 514 W. Roosevelt St.  
13 Phoenix AZ 85003  
[louisa.eberle@sierraclub.org](mailto:louisa.eberle@sierraclub.org)  
[miriam.raffel-smith@sierraclub.org](mailto:miriam.raffel-smith@sierraclub.org)  
[rose.monahan@sierraclub.org](mailto:rose.monahan@sierraclub.org)  
[cpotter@swenergy.org](mailto:cpotter@swenergy.org)  
[czwick@wildfireaz.org](mailto:czwick@wildfireaz.org)  
[briana@votesolar.org](mailto:briana@votesolar.org)  
[brendon@gabelassociates.com](mailto:brendon@gabelassociates.com)  
[Sandy.bahr@sierraclub.org](mailto:Sandy.bahr@sierraclub.org)  
[ezuckerman@swenergy.org](mailto:ezuckerman@swenergy.org)  
[janderson@aclpi.org](mailto:janderson@aclpi.org)  
[sbatten@aclpi.org](mailto:sbatten@aclpi.org)  
[thogan@aclpi.org](mailto:thogan@aclpi.org)

21 By: ML  
22  
23  
24  
25  
26

**BEFORE THE ARIZONA CORPORATION COMMISSION**

**COMMISSIONERS**

BOB BURNS, CHAIRMAN  
BOYD DUNN  
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IN THE MATTER OF THE APPLICATION OF  
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Docket No. E-01345A-19-0236

Direct Rate Design Testimony of

**Brendon J. Baatz**

**REDACTED VERSION**

on behalf of

**Southwest Energy Efficiency Project and Western Resource Advocates**

October 9, 2020

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### Exhibit List

Exhibit	Description
BJB-1	Baatz Resume
BJB-2	APS Response to SWEEP DR 2.8
BJB-3 (Highly Confidential)	APS Response to SWEEP DR 1.11, Arizona Public Service customer focus groups to test the communications strategy for the new rates
BJB-4 (Highly Confidential)	APS Response to SWEEP DR 1.11, Arizona Public Service customer satisfaction study on the prior time-of-use demand rates
BJB-5	APS Response to SEIA DR 3.11
BJB-6	APS Response to SEIA DR 3.10
BJB-7	APS Residential BSC Calculation
BJB-8	APS Response to SWEEP DR 2.2
BJB-9	APS Response to SWEEP DR 1.23
BJB-10	APS Response to SWEEP DR 1.19

1       **I. INTRODUCTION**

2       **Q. Please state your name, business address, and current position.**

3       A. My name is Brendon J. Baatz. I am currently employed as a Vice President at Gabel  
4       Associates, Inc. (“Gabel Associates”), an energy, environmental, and public utility  
5       consulting firm. My primary business address is 417 Denison Street, Highland Park, New  
6       Jersey 08904. In my current position, I advise clients on a range of electric and natural gas  
7       utility regulatory matters.

8       **Q. Please summarize your professional experience and educational background.**

9       A. I have been employed with Gabel Associates since March 2018. While at Gabel Associates,  
10      I have worked for a range of public and private clients on various issues in the utility  
11      industry. The issues include retail and wholesale electric rate design, renewable energy  
12      project cost benefit analysis, and electric vehicle utility policy. I have also worked  
13      extensively on energy efficiency program design, policy, and cost benefit analysis for  
14      several clients, including gas and electric utilities.

15             Prior to my employment with Gabel Associates, I managed the utility program at  
16      the American Council for an Energy Efficient Economy (“ACEEE”). There I focused on  
17      various issues related to utility-sector energy efficiency programs, including efficiency  
18      program design, state policies, and regulatory issues affecting energy efficiency, including  
19      electric and gas rate design. While at ACEEE I published numerous reports on energy  
20      efficiency programs and policy, and also regularly spoke at conferences on related issues.  
21      I also testified in various proceedings on these issues during that time.

22             Prior to my employment with ACEEE, I was employed with the Federal Energy  
23      Regulatory Commission (“FERC”). During my employment with FERC my primary  
24      responsibilities were the review and analyses of electric utility cost of service studies in  
25      wholesale transmission and electric power rate cases. I also worked on other litigated issues  
26      while at FERC including, but not limited to, transmission capacity reservation rights,  
27      municipal power contracts, and formula rate structure and protocols. Prior to my  
28      employment with FERC, I held positions with the Maryland Public Service Commission  
29      (“PSC”) as an energy analyst and the Indiana Office of Utility Consumer Counselor  
30      (“OUCC”) as a utility analyst. While at the Maryland PSC, I worked on the EmPOWER  
31      Maryland energy efficiency programs focusing on program design, avoided cost

1 development, and other policy issues. While working at the OUCC, I testified on a variety  
2 of utility issues including, but not limited to, rate design, renewable energy credit  
3 compensation, and utility petitions for construction. I also represented the agency in several  
4 oversight boards for utility energy efficiency programs.

5 I hold a Master of Public Affairs degree from Indiana University Bloomington and  
6 a Bachelor of Science in political science from Arizona State University. I have continued  
7 my education through attendance of various seminars and conferences. I have also  
8 completed formal training in rate design, cost of service, depreciation, and other utility  
9 regulatory matters.

10 My resume is attached as Exhibit BJB-1.

11 **Q. Have you previously testified before the Arizona Corporate Commission?**

12 A. Yes, I previously testified in Docket Nos. E-01933A-15-0322 and E-01933A-19-0028 on  
13 rate design issues. I have also testified in Colorado, Oklahoma, New Jersey, Indiana,  
14 Pennsylvania, and in Washington, D.C. before FERC.

15 **Q. Please describe the organizations on whose behalf you are testifying.**

16 A. The Southwest Energy Efficiency Project ("SWEET") is a public interest organization  
17 dedicated to advancing energy efficiency as a means of promoting customer benefits,  
18 economic prosperity, and environmental protection in the six states of Arizona, Colorado,  
19 Nevada, New Mexico, Utah, and Wyoming.

20 Western Resource Advocates ("WRA") is a non-profit conservation organization  
21 working to protect and restore the natural environment of the Interior American West.  
22 WRA's Clean Energy Program works to develop and implement policies to reduce the  
23 environmental impacts of the electric power industry by promoting the expanded use of  
24 renewable energy, energy efficiency, and other clean energy resources in an economically  
25 sound manner.

26 **Q. Have you reviewed the relevant documents filed by Arizona Public Service in this**  
27 **case?**

28 A. Yes, I have reviewed Arizona Public Service Company's ("APS" or "Company")  
29 application and supporting testimony in this case. I have also reviewed relevant discovery  
30 responses.

1 **Q. Please state the purpose of your rate design testimony.**

2 A. The purpose of my rate design testimony is to offer recommendations to the Arizona  
3 Corporation Commission (“ACC” or “Commission”) in several areas, including:

- 4 1. Three-part rates for residential customers;
- 5 2. Basic service charges (“BSC”) for residential and small general service customers;
- 6 3. Time of use (“TOU”) rate design;
- 7 4. The subscription pricing pilot proposal;
- 8 5. Electric vehicle (“EV”) charging rates for residential customers;
- 9 6. Cost recovery for energy efficiency spending;
- 10 7. Amortization and return on investment for energy efficiency spending;
- 11 8. The lost fixed cost recovery (“LFCR”) mechanism; and
- 12 9. Performance based regulation (“PBR”).

13 **Q. Please describe your recommendations to the Commission in this case.**

14 A. I have several key recommendations for the Commission that I will elaborate on in greater  
15 detail throughout my testimony. I recommend the following:

- 16 1. **The Commission should freeze all residential demand rates (R-2 and R-3) to new**  
17 **customer enrollment and discontinue these rates options.** APS has failed to properly  
18 educate customers on three-part rates and to prevent further harm, Rates R-2 and R-3  
19 should no longer be available for customer enrollment. Instead, APS should default all  
20 new customers to Rate Schedule TOU-E, while also continuing to offer an optional flat  
21 rate, regardless of usage.
- 22 2. **The Commission should deny APS’s request to increase the BSC for residential**  
23 **and general service customers and set the BSC at \$8.03 for all residential rates.**  
24 APS’s proposal to increase the BSC is inappropriate for several reasons. First, APS’s  
25 proposed BSCs are not cost based. The Company’s calculation of the BSC is flawed  
26 because it includes many costs that are not customer related. Second, regardless of what  
27 the Commission decides is properly a “customer related” cost, increasing the BSC  
28 should be rejected because such increases will decrease customer control of bills and  
29 reduce the customer incentive to engage in energy efficiency and conservation. Finally,  
30 increasing the BSC, as a rate design policy, does not align with other state policies  
31 enacted to promote energy efficiency and conservation.

- 1       3. **The Commission should require APS to shorten the TOU on-peak window to three**  
2       **hours to improve customer response and better align with current APS customer**  
3       **consumption patterns and cost of service.** This recommendation would change the  
4       TOU on-peak hours from 3 p.m. through 8 p.m. to 4 p.m. through 7 p.m.
- 5       4. **The Commission should require APS to default all new residential customers to**  
6       **TOU rates.** TOU rates provide significant benefits, including peak demand reductions  
7       driven through price signals. APS has a significant number of existing customers on  
8       TOU rates. Customers understand TOU rates and respond well. Other Arizona utilities,  
9       including Tucson Electric Power (“TEP”) and UNS Electric, also default all new  
10      customers to TOU rates with seemingly high customer satisfaction. Finally, customers  
11      should maintain the option to move to a flat rate if the TOU rate is not for them.
- 12     5. **The Commission should order APS to restructure residential EV rates to provide**  
13     **price signals that encourage off-peak charging by adding a night super off-peak**  
14     **period during the summer and winter months.** A super off-peak period would  
15     incentivize customers to charge at times when the APS system has excess capacity and  
16     would likely avoid investments in new infrastructure to meet growing peak loads driven  
17     by EVs.
- 18     6. **The Commission should order APS to recover \$65 million of energy efficiency**  
19     **program costs in base rates.** Recovery of energy efficiency program costs in base  
20     rates provides certainty in funding moving forward and provides transparency  
21     regarding the ratepayer costs of all energy resources in a consistent manner.
- 22     7. **The Commission should allow APS to book energy efficiency program costs as a**  
23     **regulatory asset, amortize these costs over a seven-year period, and earn a return**  
24     **on these investments.** Energy efficiency investments should be as financially  
25     attractive to APS as other utility investments in infrastructure or generation.  
26     Amortizing these costs reduces rate impacts of programs and aligns the cost recovery  
27     approach with the timing of the benefits.
- 28     8. **The Commission should reject the APS proposal to keep some costs in the LFCR**  
29     **and should reset the adjustor to zero.** Resetting the LFCR to zero in every rate case  
30     is standard practice for lost revenue recovery mechanisms. Leaving some costs in the  
31     adjustor could lead to overcollection of costs because the billing determinants are reset

1 based on sales from the test year, which should include the “lost” sales intended to be  
2 collected in the LFCR.

- 3 9. **The Commission should require APS to submit documentation of actual lost**  
4 **revenue through an earnings test in order to collect any revenue through the**  
5 **LFCR.** APS does not currently have full revenue decoupling in place. The LFCR is  
6 intended to collect lost revenues from distributed generation and energy efficiency;  
7 however, the current adjustor still collects the lost revenue, regardless of whether or  
8 not the Company is already recovering its authorized revenues. This practice is ripe for  
9 over recovery and APS should be required to submit an earnings test in order to receive  
10 any lost revenues through the LFCR.

- 11 10. **The Commission should reject the APS proposal to conduct a subscription pricing**  
12 **pilot.** Subscription pricing is a slightly altered form of an old idea known as a fixed  
13 bill. A fixed bill does not provide customers any actionable price signal and discourages  
14 any incentive to engage in energy efficiency or install distributed generation. A fixed  
15 bill is not a cost-based approach to billing customers for electricity consumption and  
16 will lead to increases in peak demand and overall consumption. Furthermore, now is  
17 not the time for APS to conduct experiments with its customers given its recent history  
18 with customer satisfaction and its failures to properly educate customers about its rate  
19 options. If customers are interested in stabilizing their electric bills over the course of  
20 a year, budget billing is available.

- 21 11. **The Commission should initiate the already opened statewide generic**  
22 **investigation into PBR to improve utility business models in Arizona by providing**  
23 **revenue opportunities to utilities to meet specific performance metrics and goals.**<sup>1</sup>  
24 PBR would tie APS’ financial earnings with performance in critical areas, including  
25 customer satisfaction, reliability, and environmental performance. PBR can allow the  
26 Commission to promote critical performance and policy goals by using financial  
27 incentives, similar to the energy efficiency performance structure in place now.

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<sup>1</sup> See Docket No. E-00000A-20-0019, [edocket.azcc.gov/Docket/DocketDetailSearch?docketId=24146#docket-detail-container1](http://edocket.azcc.gov/Docket/DocketDetailSearch?docketId=24146#docket-detail-container1)

1       **I. RESIDENTIAL THREE-PART RATES ARE NOT IN THE**  
2       **PUBLIC INTEREST AND SHOULD BE FROZEN TO NEW**  
3       **CUSTOMERS AND PHASED OUT**

4       **Q. Please summarize the APS proposal for residential three-part rates in this case.**

5       A. APS is proposing changes to its existing three-part rate options for residential customers,  
6       which include Saver Choice Plus (R-2) and Saver Choice Max (R-3). These changes  
7       include an increase in the BSC by 2.4%, the addition of a winter super off-peak TOU  
8       window, and small increases to energy/demand rates based on proposed increases to retail  
9       revenues.<sup>2</sup> Both rate options, Saver Choice Plus and Saver Choice Max, were newly  
10      implemented rates following the approval of APS' last rate case in 2017.

11      **Q. Please provide background on the approval and implementation of the Saver Choice**  
12      **Plus and Saver Choice Max rate options.**

13      A. The two residential demand charge rate options were approved in the most recent APS rate  
14      case in August 2017 in Decision No. 76295,<sup>3</sup> which ratified the settlement on many issues  
15      reached by APS and the majority of the intervenors. As part of the approved settlement  
16      agreement, APS agreed to develop and file an education and outreach plan for new rate  
17      options. The stated intention of this plan was to educate and help customers manage their  
18      new rate options, including services and tools to help customers manage utility costs.<sup>4</sup>

19              Following the implementation of the new rates, which were a significant departure  
20      from most of APS' prior rate plans, APS and the Commission received numerous  
21      complaints regarding rate increase notices, customers' lack of understanding of the  
22      "modernized" rate designs, and concerns about being placed on demand rates.<sup>5</sup> The volume  
23      of customer complaints was so significant that the Commission opened an investigation  
24      into the effectiveness of APS' Customer Outreach and Education Plan ("COEP"). As part  
25      of this process, Commission Staff commissioned an independent review of the APS COEP.  
26      APS also experienced a substantial increase in late payments and customer defaults  
27      following the new rates' implementation, further highlighting significant issues with  
28      customer understanding and response to the new rates.

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<sup>2</sup> Hobbick Direct at page 3.

<sup>3</sup> Arizona Corporate Commission, Decision No. 76295 in Docket No. E-01345A-16-0036.

<sup>4</sup> *Ibid.* Settlement Agreement Section 27.1, page 24.

<sup>5</sup> Arizona Corporate Commission, Decision No. 77270 in Docket No. E-01345A-19-0003.

1 **Q. Please summarize the key findings of the independent review of the APS COEP.**

2 A. The ACC Staff released the evaluation of the COEP on May 19, 2020. The report was  
3 completed by independent consultant Barbara Alexander (“Alexander Report”). A  
4 summary review of the report’s findings showed:<sup>6</sup>

- 5 - The majority of information communicated to customers in APS’ COEP was **not**  
6 reasonable and understandable.
- 7 - Some customers may have been dissatisfied with being moved to new, sometimes  
8 differently structured rate plans and rate plans with different peak hours than  
9 previous rate plans.
- 10 - Some customers moved to new rate plans may have experienced or perceived that  
11 the rate plans caused significant increases in their bills.
- 12 - Some customers were unhappy with being placed on rate plans with a demand  
13 component.
- 14 - The information provided by APS in its rate increase notices and personalized  
15 letters failed to convey certain important information, including that these  
16 additional increases in bills were dependent on customer-specific circumstances,  
17 including the specific rate plans that customers were on before and after the  
18 transition, and behavioral changes in energy usage patterns under the new rate plans  
19 which could minimize bill increases, such as shifting usage to accommodate the  
20 new on-peak hours and demand charges.

21 These findings suggest a failure on the part of APS to properly educate and inform  
22 customers of the new rate options.

23 **Q. Are there other indications of an APS failure to properly educate and inform**  
24 **customers on the new rate options approved in its last rate case?**

25 A. Yes, there are several other indicators of an APS failure to educate customers on the new  
26 rate options that were approved in its last rate case. In early 2019, the ACC directed its  
27 Staff to initiate a rate review of APS’s current rates to determine if the Company had been  
28 over earning.<sup>7</sup> The rate review found that the design of the Company’s new rate plans may  
29 have incentivized the selection of demand rates over other options. The review also found

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<sup>6</sup> *Ibid.* pages 3-5.

<sup>7</sup> ACC Utilities Division Staff, Request for a New Docket. January 9, 2019. Docket No. E-01345A-19-0003.  
[docket.images.azcc.gov/0000195010.pdf](https://docket.images.azcc.gov/0000195010.pdf)

that APS had been over earning, collecting \$6.7 million of gross margin in 2018 associated with higher than expected revenues due to variances between assumptions in the billing determinants used in the 2016 rate case and actual 2018 billing determinants.<sup>8</sup>

**Q. Please expand on other indicators of the APS failure to properly roll out the new rates.**

A. The number of defaults and late payments also increased following the implementation of the new rates. Table 1 shows the number of residential customer late payments and defaults by year from 2016 through 2018. As the data show, the number of late payments increased by 47% from 2016 to 2018. The number of defaults nearly doubled from 2017 to 2018.<sup>9</sup>

*Table 1. APS Residential Late Payments and Defaults 2016-2018*

Year	# of Late Payments	# of Defaults
2016	1,113,755	85,433
2017	1,595,102	55,303
2018	1,640,500	105,206

**Q. Would you expect an increase in the number of defaults and late payments during this time period in the absence of the APS rate design changes?**

A. No, I would not. The APS service territory was experiencing economic growth during this period. Using data from the United States Census, I reviewed the population living below the poverty level for all counties in the APS service territory (Apache, Cochise, Coconino, Maricopa, Navajo, Pinal, Yavapai, and Yuma). The results showed that from 2015-2018 the population living below the poverty level declined by 17%. Table 2 shows this data.

*Table 2. Population Below Poverty Line in APS Service Territory Counties 2015-2018.<sup>10</sup>*

	2015	2016	2017	2018
Population below poverty level	934,935	922,735	893,190	861,357
% of population below poverty level	17.9%	17.4%	16.6%	15.6%

The significant increase in the number of residential late payments and defaults during a period of economic growth is unexpected and is likely explained by the rate changes and

<sup>8</sup> Arizona Corporate Commission, Decision No. 77270 in Docket No. E-01345A-19-0003, page 7.

<sup>9</sup> See Exhibit BJB-2 APS Response to SWEEP 2.8.

<sup>10</sup> U.S. Census Bureau, 2009-2014 American Community Survey 5-Year Estimates.

[data.census.gov/cedsci/table?q=United%20States&tid=ACSDP1Y2019.DP05&hidePreview=false](https://data.census.gov/cedsci/table?q=United%20States&tid=ACSDP1Y2019.DP05&hidePreview=false)

1 implementation of new rate options for customers. In an environment of increased  
2 prosperity and favorable economic conditions, you would expect the number of late  
3 payments and defaults to decrease, not increase.

4 **Q. Were there other issues with the APS roll out of its new rates?**

5 A. Yes. As part of its rate rollout and COEP, the Company developed a rate comparison tool  
6 that would allow customers to determine the best rate option based on their prior  
7 consumption patterns. The tool developed by APS included flaws that gave customers  
8 inaccurate results, leading some customers to subscribe to rates that were not in their best  
9 interest. These customers ended up facing higher bills than needed because of the flawed  
10 tool.

11 **Q. In your opinion, do you think the rate plan names contributed to customer**  
12 **confusion?**

13 A. Yes, I think it is likely the rate plan names confused customers. The two demand rate plan  
14 names, Saver Choice Plus and Saver Choice Max, imply that a customer would have a  
15 lower bill than the TOU-E rate (Saver Choice) and the flat rate plans, Lite Choice and  
16 Premier Choice. The names also do not indicate a difference between a flat rate, TOU rate,  
17 or demand rate plan.

18 **Q. Regarding the APS COEP, did you find any other aspects problematic in terms of**  
19 **potential for customer confusion?**

20 A. Yes. In the Final COEP, APS stated that it “will focus its education plan on notifying  
21 customers of their Best Rate, a plan that provides them the lowest electricity bill based on  
22 the most recent year of their own usage data.”<sup>11</sup> As noted in the Alexander Report, APS  
23 usually promoted the demand rate options as the “best plan” for customers.<sup>12</sup> This is  
24 problematic for several reasons. One, APS’s own rate analysis tool was flawed and  
25 incorrectly predicted a customer’s “best plan.”<sup>13</sup> This created customer confusion and  
26 harmed some customers.

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<sup>11</sup> Arizona Public Service. Final Customer Education and Outreach Plan. September 29, 2017. E-01345A-16-0036 and E-01345A-16-0123. Page 2. [docket.images.azcc.gov/0000182982.pdf](https://docket.images.azcc.gov/0000182982.pdf)

<sup>12</sup> Alexander, B. “An Evaluation of Arizona Public Service Company’s Customer Education Plan and It’s Implementation.” May 19, 2020. Prepared on Behalf of the Staff of the Arizona Corporation Commission. Page 25. [docket.images.azcc.gov/E000006584.pdf](https://docket.images.azcc.gov/E000006584.pdf)

<sup>13</sup> *Ibid.* page 9.

Two, APS's customers did not understand demand rates prior to the roll out of the new rate plans. [REDACTED]

[REDACTED]

Three, telling customers a demand rate plan is the "best rate" for them because of twelve months of prior consumption is misleading. Under a demand rate, it is very easy to incur a large demand charge if you are not mindful of which appliances and devices are running at one time, leading to a much higher bill. As previously stated, most customers were not familiar with a demand rate concept and [REDACTED]

[REDACTED]. Therefore, telling these customers that a demand rate option is the "best plan" for them and not providing the tools customers needed to respond to different rates is problematic.

**Q. What conclusions do you draw from the large increase in customer complaints related to rates, the customer education failures documented in the Alexander Report, the spike in late payments and defaults, and the documented over recovery of revenues shown in the Staff Report?**

**A.** The evidence indicates a substantial failure on the part of APS to properly roll out the new rates from the 2016 rate case. Customers clearly did not understand the new rates and did not respond in a meaningful way. As a result, many customers faced higher than expected bills and APS accrued higher than expected earnings. The significant increase in late payments and customer defaults is also clear evidence of a failure on APS's part to educate customers.

**Q. Do have specific recommendations for the Saver Choice Plus and Saver Choice Max rate options?**

<sup>14</sup> See Exhibit BJB-3 (Highly Confidential) APS Response to SWEEP DR 1.11.

<sup>15</sup> See Exhibit BJB-4 (Highly Confidential) APS Response to SWEEP DR 1.11.

1 A. Yes. I recommend the Commission discontinue these rates for new customers and phase  
2 out existing customers over time. I am not recommending APS remove all customers from  
3 these rate options at this time, but both R-2 and R-3 options should be frozen so no other  
4 customers can be added to these rate plans. There are several reasons why I am  
5 recommending APS discontinue the residential three-part rate options. APS has failed to  
6 properly educate customers on the new rate options. Demand charges are a poor price  
7 signal to residential customers as to when and how to use electricity in a way that benefits  
8 the system as a whole. Finally, three-part rates for residential customers are inferior to other  
9 time-based rate options, including TOU rates, in many respects. Properly designed TOU  
10 rates are better understood by customers, elicit a more significant price response, and are  
11 already familiar to APS customers.

## 12 **II. APS SHOULD UPDATE TOU RATES TO IMPROVE CUSTOMER** 13 **RESPONSE AND MAXIMIZE SYSTEM BENEFITS**

14 **Q. Please describe the APS proposal regarding TOU in this proceeding.**

15 A. The Company is proposing to increase the BSC and add a winter super off-peak period to  
16 demand TOU rates (R-2 and R-3). The super off-peak period would be 10 a.m. to 3 p.m.  
17 during winter months only.

18 **Q. Please summarize your recommendations regarding the APS Residential TOU rates.**

19 A. In order to maximize benefits of TOU rates and customer satisfaction, I offer the following  
20 recommendations:

- 21 1. APS should make the TOU-E rate option the default rate for all new residential  
22 customers;
- 23 2. The on-peak time window should be reduced to three hours instead of the current  
24 five-hour window; and
- 25 3. A super off-peak period should be added for EV customers to incentivize customers  
26 to charge during super off-peak hours.

27 I elaborate on each of these recommendations below.

### 28 **a. APS Should Make the TOU-E Rate Option the Default Rate for All** 29 **New Residential Customers.**

30 **Q. What is the current default rate for APS residential customers?**

1 A. Currently, APS has no default rate option for residential customers. According to the  
2 Company, when a new customer initiates new service over the phone, an APS customer  
3 service representative will work with the customer to determine the “best” rate option.<sup>16</sup>  
4 As the past several years have shown, APS has a poor track record of choosing rate options  
5 for customers. TOU rates also are the best rate option offered by APS for reducing customer  
6 peak demand. Finally, APS’s (and other Arizona utilities’) customers have had a generally  
7 positive experience on TOU rates. For these reasons, APS should default all new customers  
8 on TOU-E, while still allowing customers an opportunity to switch to a flat rate option,  
9 because TOU rates are not the best option for all customers.

10 **Q. Do other utilities in Arizona default new customers to TOU rates?**

11 A. Yes. I am aware of UNS Electric and Tucson Electric Power. For UNS Electric, the  
12 Commission required a two-part TOU rate to be the default rate for new customers in  
13 August 2016.<sup>17</sup> For TEP, the Commission approved TOU as the default option for  
14 residential customers in February 2017.<sup>18</sup> By adopting TOU as the default rate option for  
15 new residential customers, APS would be consistent with other investor owned utilities in  
16 Arizona.

17 **Q. What are the benefits of defaulting new customers to TOU rates?**

18 A. When designed properly, TOU rates have the ability to produce substantial peak demand  
19 reductions. These peak demand reductions lower system costs by avoiding the need to  
20 construct new generation, transmission, and distribution infrastructure. TOU rates also give  
21 customers more control over their electric bills and may have less harmful impacts on low  
22 income customers when compared with a simple two-part rate with a high BSC. TOU rates  
23 also offer the Company a reasonable opportunity to recover Commission authorized costs.

24 **Q. Do customers understand and respond well to TOU rates?**

25 A. Yes, previous studies have shown that customers do understand and respond well to TOU  
26 rates. A recent series of studies was conducted by the U.S. Department of Energy under  
27 the Smart Grid Investment Grant Program. Ten utilities conducted 11 consumer behavior  
28 studies to better understand customer acceptance, retention, and response to time varying

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<sup>16</sup> APS response to Staff DR 8.3.

<sup>17</sup> Arizona Corporate Commission, Decision No. 75697, Docket No. E-04204A-15-0142.

<sup>18</sup> Arizona Corporate Commission, Decision No. 75975, Docket No. E-01933A-15-0322.

1 rates.<sup>19</sup> The studies were done over a period of several years under rigorous scientific  
2 research protocols. Major findings included the following:

- 3 • Opt out approaches (defaulting customers onto specific rates) were more cost  
4 effective than opt in.
- 5 • A majority of customers defaulted onto TOU rates at Sacramento Municipal Utility  
6 District (“SMUD”) were satisfied with the TOU rate based on customer surveys.
- 7 • Customer technologies such as programmable thermostats produced higher peak  
8 demand reductions for time varying rates.
- 9 • Peak demand reductions were higher for rate designs with higher peak to off-peak  
10 ratios on average.

11 **Q. Please describe the potential peak demand reductions TOU rates may provide.**

12 A. TOU rates can substantially reduce peak demands. A report by the Rocky Mountain  
13 Institute noted that well-designed time-based rates (including TOU, critical peak pricing,  
14 or peak time rebates) “are effective at achieving their objective of providing a price signal  
15 to customers about when to use energy.”<sup>20</sup> This same report noted that several regions are  
16 transitioning to default TOU rates because of this effectiveness.

17 According to a 2013 article by Dr. Ahmad Faruqui, TOU pricing yields significant  
18 load reductions.<sup>21</sup> In the study, Dr. Faruqui reviewed 34 pricing studies, under which 163  
19 experimental treatments were conducted. The pricing pilots evaluated customer response  
20 to several forms of dynamic pricing including: TOU, peak time rebates, variable peak  
21 pricing, and critical peak pricing. Some of the pricing experiences also included a  
22 technology intervention, like an in-home energy usage display or home energy monitor  
23 that provides feedback on energy consumption. Figure 1 below shows the percentage of  
24 peak demand reduction achieved for all 163 pricing pilots sorted by rate option. As the  
25 figure shows, TOU pricing produced substantial peak demand reductions – with many peak  
26 reductions from TOU pricing producing peak reductions in the 10% - 40% range.

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<sup>19</sup> United States Department of Energy. 2016. *Customer Acceptance, Retention, and Response to Time-Based Rates from the Consumer Behavior Studies*. Smart Grid Investment Grant Program.

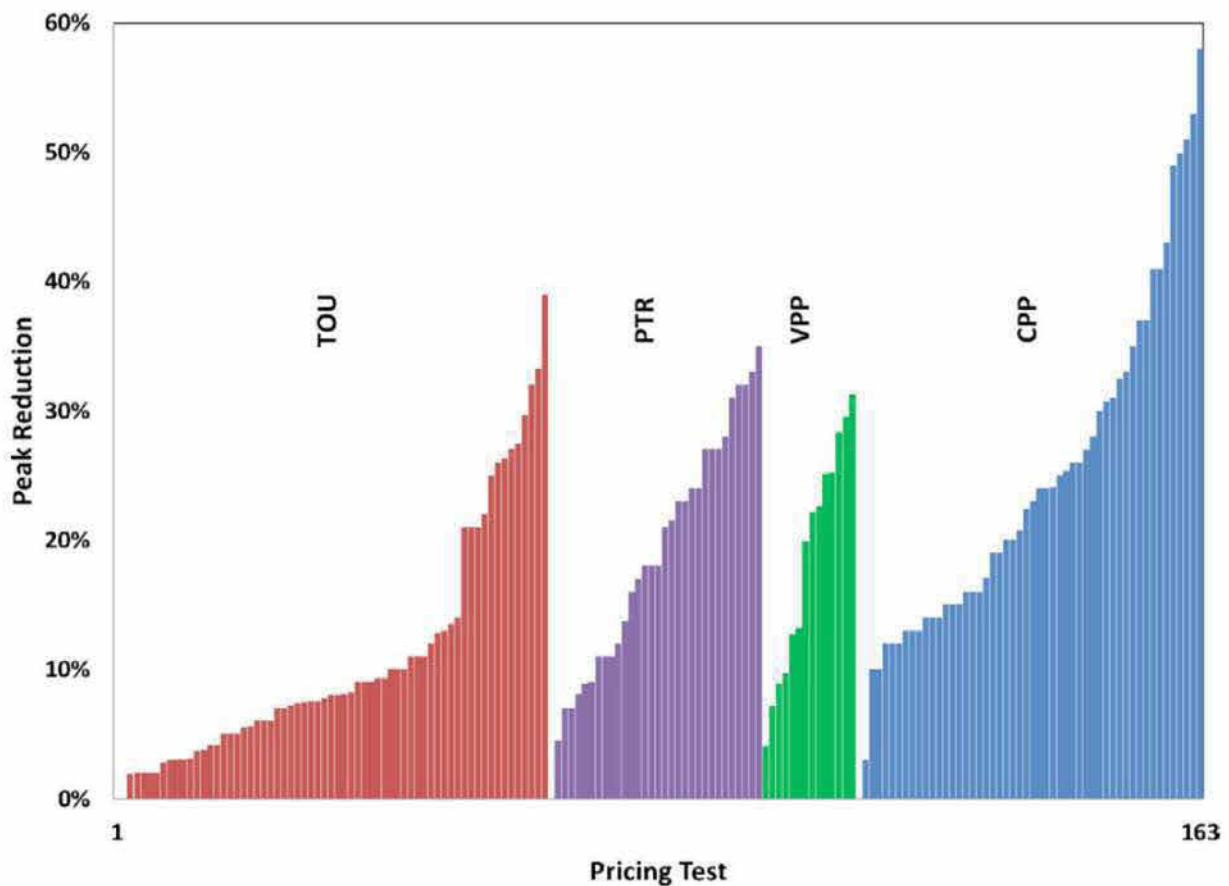
[energy.gov/sites/prod/files/2015/06/f24/ARRA-CBS\\_interim\\_program\\_impact\\_report\\_June2015.pdf](https://energy.gov/sites/prod/files/2015/06/f24/ARRA-CBS_interim_program_impact_report_June2015.pdf)

<sup>20</sup> Rocky Mountain Institute. 2016. “A Review of Alternative Rate Designs: Industry Experience with Time-Based and Demand Charge Rates for Mass-Market Customers.” [rmi.org/wp-content/uploads/2017/04/A-Review-of-Alternative-Rate-Designs-2016.pdf](http://rmi.org/wp-content/uploads/2017/04/A-Review-of-Alternative-Rate-Designs-2016.pdf)

<sup>21</sup> Faruqui, A. and S. Sergici. 2013. “Arcturus: International Evidence on Dynamic Pricing.” *The Electricity Journal*. Volume 26, Issue 7, August/September. [sciencedirect.com/science/article/abs/pii/S1040619013001656](http://sciencedirect.com/science/article/abs/pii/S1040619013001656)

1

Figure 1. Peak demand reduction percentages for 163 pricing experiments<sup>22</sup>



2 Note: TOU = time of use, PTR = peak time rebate, VPP = variable peak pricing, CPP = critical peak  
 3 pricing.

4 **Q. Please identify the benefits of expanding the number of customers on TOU rates.**

5 A. There are many benefits to implementing and expanding utilization of TOU rates. The  
 6 potential benefits from load shifting and conservation in response to TOU include lower  
 7 customer bills; reduced wholesale market prices; avoided or deferred capacity investments  
 8 in generation, transmission, and distribution; better integration of intermittent renewable  
 9 energy resources; and, potentially, reduced pollution. TOU rates may also provide higher  
 10 returns on investment in distributed energy resources, such as solar energy and energy  
 11 storage, as well as energy efficient appliances.

12 **Q. Please expand upon how TOU rates assist in providing the benefits discussed above.**

13 A. TOU rates produce several significant benefits. These benefits include:

<sup>22</sup> Ibid.

1. Lower customer bills - Under flat pricing, customers pay the same rate for electricity during all hours of the day. As a consequence, customers have no knowledge of actual prices across the hours of the day and, therefore, use electricity without considering the economics of the product that they are purchasing. TOU rates provide customers with appropriate price signals to allow them to modify their electricity usage patterns to use electricity more efficiently. As such, TOU rates allow customers to reduce their utility bills by shifting usage to the less costly periods through heightened price sensitivity.
2. Reduced wholesale prices - The benefits of TOU rates can reach all market participants, creating a more efficient and less costly system. Reduced peak demand and lower levels of congestion can help avert calling on more expensive power generation, allowing wholesale markets to clear at lower prices. Avoiding the dispatch of higher priced generation results in a lower average cost of producing electricity and thus a lower price for those who choose to remain on flat pricing.
3. Avoided or deferred capacity investments - To the extent that TOU rates are able to mitigate system wide peak demand by shifting energy consumption to off-peak times, the need for additional power plants and transmission and distribution infrastructure can be deferred or avoided.
4. Better integration of intermittent renewable energy resources – TOU rates can integrate and help drive the deployment of distributed energy resources, such as solar photovoltaics (PV), storage, and energy efficiency. TOU rates can also help align energy demand with the growing penetration of distributed energy resource supply, leading to a more efficient management of the electric system and increased utilization of renewable resources, which should reduce fossil-based air emissions.
5. Improved environmental outcomes – TOU rates encourage conservation and shifting of electricity consumption to times when electricity is cheaper, behaviors that are further enhanced by stimulating investments in energy efficiency and battery storage. Load shifting from on-peak to off-peak periods and reduced overall load from conservation can result in a decrease of polluting emissions from the power sector.

**b. The On-peak Time Window Should Be Reduced to Three Hours  
Instead of The Current Five-Hour Window**

**Q. What is the APS proposed TOU window for residential rates?**

1 A. According to the filed proposed Rate Schedule TOU-E, the on-peak time period is 3 to 8  
2 p.m., Monday through Friday year round. The rate also includes a super off-peak period in  
3 the winter months (November through April) from 10 a.m. to 3 p.m. All other hours are  
4 off-peak.

5 **Q. What are the general objectives of TOU rates?**

6 A. The general purpose of TOU rates is to reduce demand during peak periods or encourage  
7 consumption in off-peak periods. This objective is accomplished by providing a pricing  
8 signal directly to customers that discourages consumption during specified hours via a  
9 higher price. By reducing peak demand, cost – both present and future – can be decreased.

10 Generation costs are reduced by avoiding the dispatch of higher priced supply. Peak  
11 load reductions generally do not lower current distribution costs because the majority of  
12 these costs are fixed in the short-run. However, future generation and distribution costs can  
13 be avoided through reducing peak loads because all utility system costs are variable in the  
14 long-run. For example, reductions in peak demand, including noncoincident peak demand  
15 at the class level, allow utilities to avoid making additional investments in new  
16 infrastructure to meet growing demand. Because these investment decisions are made prior  
17 to the actual real-time delivery of energy, they cannot be changed in the short term but can  
18 be changed long-run.

19 The establishment of on and off-peak periods considers several variables including:  
20 system and class hourly loads, hourly cost of service considerations, and customer  
21 comprehension, ability, and willingness to respond. There are often tradeoffs in designing  
22 TOU rates. For example, a TOU rate will often include the same on-peak periods for  
23 summer and winter, even if the customer demand and system costs are significantly lower  
24 in the winter. This is to simplify the rate for customer understanding and communication.  
25 The balancing of objectives also may result in a TOU rate that is not completely cost based,  
26 but still achieves its stated targets.

27 **Q. Do you support the on-peak period as proposed by APS?**

28 A. No. The on-peak period is too long and is not based on current information. APS developed  
29 the on-peak period using forecasted system summer peak hours, not the actual residential  
30 customer class summer peak. The Company also relied on forecasted system costs to

develop the on-peak period instead of actual costs, which I believe is a flawed approach.<sup>23</sup> I recommend APS use an on-peak window of 4 to 7 p.m., Monday through Friday year round. This time window allows customers enhanced opportunity to respond to the rate and is better aligned with the residential customer class summer peak and cost of service.

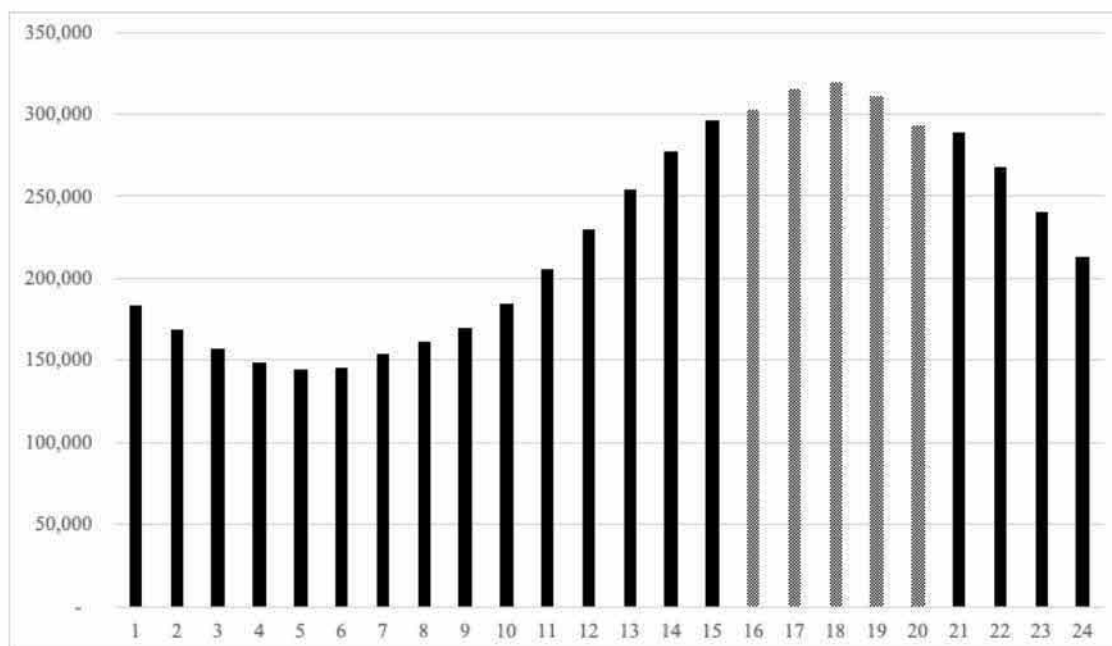
**Q. Please describe the basis for your recommendation for a shorter on-peak window.**

A. The current (and proposed) on-peak window of 3 to 8 p.m. covers a five-hour period, which is excessively long for customers to adequately respond. A shorter window would allow customers greater flexibility in changing behaviors to shift demand to off-peak hours. A shorter window would also allow customers a greater opportunity to pre-cool homes, which is more challenging under a five hour on-peak window.

**Q. Did specific APS data also inform your recommendation?**

A. Yes. I reviewed the residential summer hourly consumption for non-solar customers in calendar year 2019. Figure 2 shows the hourly load for weekdays during the summer months.

*Figure 2. APS 2019 Summer Weekday Residential Gross Hourly Load.<sup>24</sup>*



The hours shaded in gray are the current APS TOU-E on-peak hours. As the chart shows, the three highest hours of consumption for the residential customer class are from 4 to 7

<sup>23</sup> Miessner Settlement Rebuttal Testimony, Docket Nos. E-01345A-16-0036 & E-01345A-16-0123.

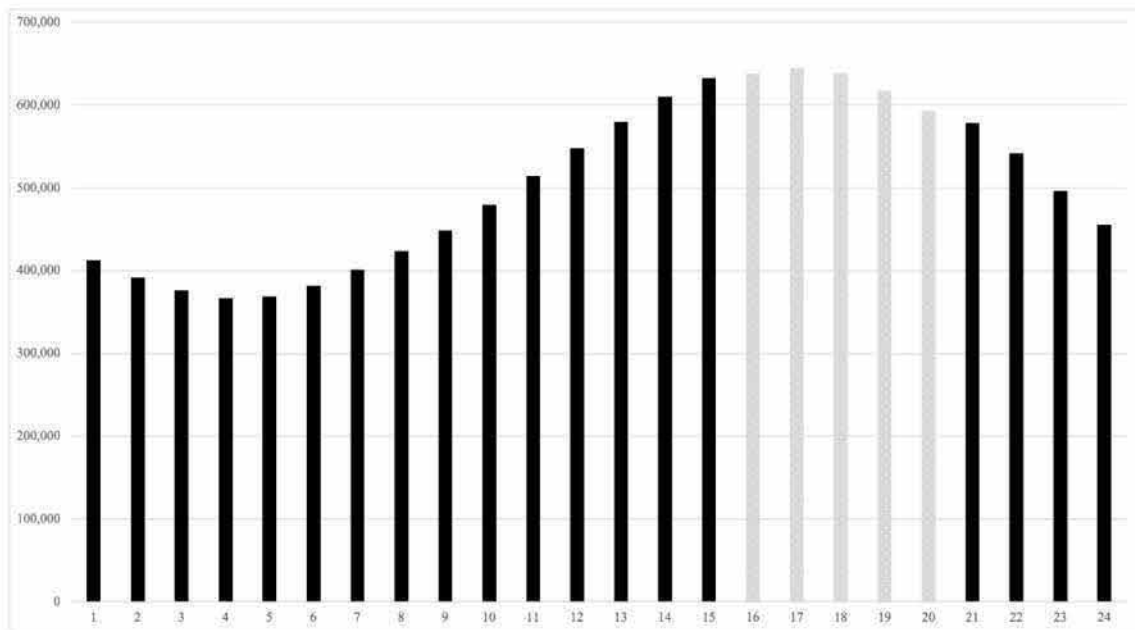
<sup>24</sup> See Exhibit BJB-5 APS Response to SEIA 3.11.

p.m. (shown in Figure 2 as hours ending 17, 18, and 19). The APS proposal includes additional hours, including 7 to 8 p.m. (hour ending 20), which is not even the fifth highest hour during this period.

**Q. APS proposes using the system hourly load to design residential TOU rates instead of the residential class hourly load. Please respond.**

A. APS argued in its prior rate case that the residential TOU on-peak periods should be based on system load, not residential class load.<sup>25</sup> However, this recommendation was also based on a forecast. Figure 3 shows the APS summer weekday gross system load for 2019. The hours shaded in gray are the current TOU-E on-peak hours. As the figure shows, the current on-peak periods are not supported by current customer conditions. The 2019 gross weekday hourly system load supports an on-peak period that occurs earlier in the day, which would also facilitate a better price response from residential customers.

*Figure 3. APS Hourly Summer Weekday Gross System Load.<sup>26</sup>*



**Q. You previously mentioned APS relied on forecasted cost data to develop TOU on-peak periods. Please expand.**

A. In Settlement Rebuttal testimony, APS witness Charles Miessner outlined the Company's justification for choosing the 3 to 8 p.m. on-peak window.<sup>27</sup> Mr. Miessner references an

<sup>25</sup> Miessner Settlement Rebuttal Testimony, Docket Nos. E-01345A-16-0036 & E-01345A-16-0123.

<sup>26</sup> See Exhibit BJB-6, APS Response to SEIA 3.10.

<sup>27</sup> Miessner Settlement Rebuttal Testimony, Docket Nos. E-01345A-16-0036 & E-01345A-16-0123.

energy and capacity cost heat map to support his position. The “heat map” was based on levelized costs from 2020 to 2035, meaning the Company based rates filed in 2016 on forecasted costs from 2020 to 2035 for energy and capacity. A significant portion of the on-peak costs are driven by forecasted costs to install a combustion turbine in 2026.

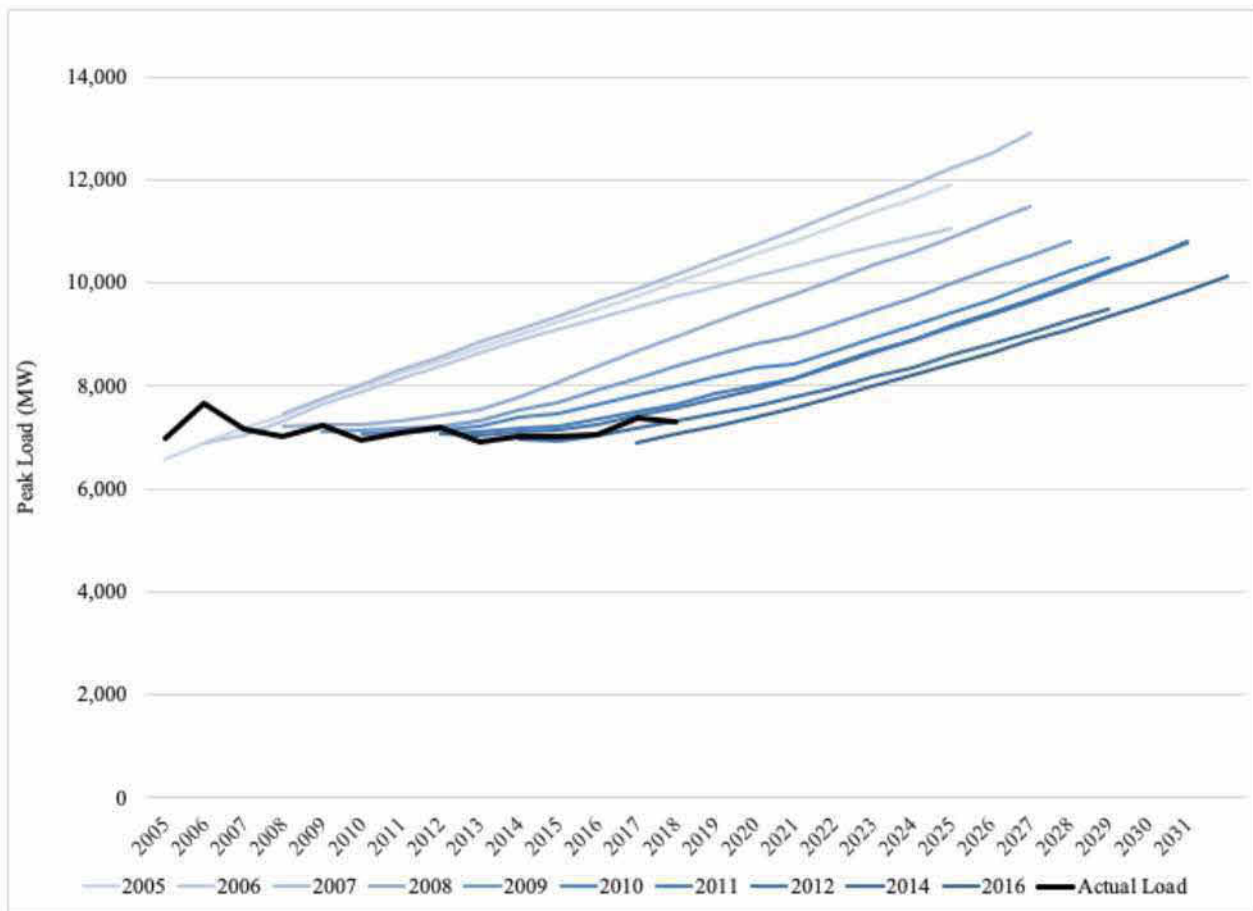
**Q. Do you think this is a reasonable approach?**

A. No, I do not. It is unreasonable and problematic for APS to design rates based on forecasted system conditions ten years into the future. The cost assumptions from APS are also outdated, unreliable, and should be rejected by the Commission as a basis for designing current rates.

**Q. How has APS performed in forecasting future load?**

A. APS has a poor record of load forecasting. Figure 4 shows APS load forecasts compared with actual load. As the figure shows, APS has significantly overestimated peak load.

*Figure 4. APS Load Forecasts versus Actual Load. Source: Pinnacle West Annual Reports, Statistical Report Supplements, and Load Forecasts.*



1 **Q. Please summarize your recommendations to the Commission on the issue of on-peak**  
2 **hours for the TOU-E rate.**

3 A. I recommend the Commission adopt an on-peak period of 4 to 7 p.m. based on the current  
4 system conditions. If conditions change that require a redesign of the TOU-E rate, APS  
5 should file the requested changes at that time based on actual and current information.

6 **c. APS Should Include a Super Off-peak Period in Summer Months and**  
7 **Evening Super Off-peak Period in Winter Months for Rate Schedule**  
8 **TOU-E to Encourage Managed EV Charging**

9 **Q. Does APS currently offer a residential rate option specifically targeted to EV**  
10 **owners?**

11 A. No. APS does not currently offer a residential rate option specifically tailored for  
12 residential customers with EVs. The APS TOU-E rate includes off-peak periods in summer  
13 and winter, and a super off-peak period from 10 a.m. to 3 p.m. in the winter months. The  
14 price differentials of these rate options, the price difference between the on and off-peak  
15 periods, are sufficient to drive customer behavior change. However, there is currently no  
16 super off-peak period defined for the summer months on the TOU-E rate.

17 **Q. Why should APS add a super off-peak period in the summer months?**

18 A. A nighttime super off-peak period would offer customers a lower rate during those hours  
19 to encourage charging during super off-peak periods when system utilization is lowest.  
20 This approach would reduce charging during higher utilization hours, lowering demand on  
21 the distribution system and avoiding the need to build new capacity. The current TEP super  
22 off-peak period for its residential TOU-EV rate option is from 10 p.m. to 5 a.m. in all  
23 months of the year.<sup>28</sup> Given the residential hourly load shape shown in Figure 2, a period  
24 of 11 p.m. to 5 a.m. for APS customers would be reasonable.

25 **Q. Why should APS add an additional super off-peak period at night in the winter**  
26 **months?**

27 A. The addition of a super off-peak period at nighttime for winter months would encourage  
28 charging during super off-peak periods when system utilization is lowest. A nighttime  
29 super off-peak period would also be consistent with the summer month recommendation  
30 above, which would allow consistent messaging to customers about when to charge. I am

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<sup>28</sup> Tucson Electric Power. Super Off-Peak Time-of-Use EV Plan. [tep.com/electric-vehicles/super-off-peak-time-of-use-ev-plan/](http://tep.com/electric-vehicles/super-off-peak-time-of-use-ev-plan/)

not proposing that APS eliminate the 10 a.m. to 3 p.m. super off-peak period in winter months at this time.

**Q. Why is it important for APS to manage EV charging through rate design?**

A. The rise of EVs has the potential to be one of the most significant changes to take place in the electricity sector over the coming decades. For instance, the combination of policy support for transportation electrification and the rapid decline in costs of batteries have led almost all major manufacturers in the automobile industry to make significant investments in electric vehicles.

The proliferation of EVs over the next decade will significantly increase electric demand in the APS service territory. The increased demand, if not properly planned for and managed, will require expansion of distribution infrastructure, which will increase costs for all customers. If APS can plan properly and manage the new demand from EVs, it can reduce future costs by encouraging customers to charge at times where system capacity is ample.

**Q. Do APS ratepayers stand to benefit from increased EV deployment?**

A. Yes. There are a number of potential benefits, including: improved air quality and public health, reduced consumer fuel costs, and enhanced utilization of the electricity grid and potential to lower electricity rates.

**Q. Please describe each of these benefits in greater detail.**

A. These benefits include:

- Reduced emissions and improved public health: Because electric vehicles have no tailpipe emissions, they can deliver significant air quality and public health benefits. As the emissions intensity of electricity production decreases due to higher levels of renewable energy penetration, these benefits will grow. SWEEP conducted an analysis in 2013 of the emissions associated with driving an EV versus a comparable gasoline-fueled vehicle in Maricopa County. This analysis revealed that there are already very significant emissions reductions associated with driving an EV in Arizona. The largest emissions reductions are for Volatile Organic Compounds or VOCs (99% reduction) and carbon monoxide (99% reduction), with significant additional reductions in sulfur dioxide (93% reduction), nitrogen oxides (76% reduction), and particulate matter (60% reduction for PM2.5 and 45%

reduction for PM10). Since VOCs and nitrogen oxides are the major precursors to ozone formation, widespread adoption of EVs could be an important strategy for addressing the region's ozone challenges.<sup>29</sup> Further, EVs do not emit carbon dioxide, which accelerates climate change. Climate change poses risks of increased temperatures, drought, and wildfires in Arizona.<sup>30,31</sup>

- Reduced consumer fuel costs: Because electric motors are much more efficient than internal combustion engines, fuel costs are significantly lower for EVs. The average American household spends \$2,000-\$3,000 on gasoline each year. EV drivers can save between \$700-\$1,400 annually on fuel costs — money that consumers can spend directly into the Arizona economy. Depending on EV adoption rates and gasoline prices, the total economic benefit to Arizona in reduced fuel costs could be between \$75-\$489 million per year by 2030. If Arizona were to achieve the level of one million EVs by 2050, this would lead to annual consumer savings of \$700 million- \$1.4 billion.<sup>32,33</sup>
- Enhanced utilization of the electricity grid and potential to lower electricity rates: EVs offer utilities an opportunity to increase the demand for electricity, especially during off-peak hours when there can be significant underutilized electric generating capacity (assuming proper price signals are established). In order to meet peak load demands during summer months, utilities generally have significant amounts of generating capacity that is unused or underutilized during most of the year, especially during the late evening and early morning hours. If underutilized capacity is used more frequently, the fixed capital costs will be spread out over more generation and sales, which can reduce pressure on rates for all customers.

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<sup>29</sup> SWEEP. 2013. "Air Quality and Economic Benefits of Electric Vehicles in Arizona." [swenergy.org/data/sites/1/media/documents/publications/documents/AZ%20EV%20AirQuality.EconAnalysis.9.26.13%20.pdf](http://swenergy.org/data/sites/1/media/documents/publications/documents/AZ%20EV%20AirQuality.EconAnalysis.9.26.13%20.pdf)

<sup>30</sup> Environmental Protection Agency. 2016. *What Climate Change Means for Arizona*. [19january2017snapshot.epa.gov/sites/production/files/2016-09/documents/climate-change-az.pdf](http://19january2017snapshot.epa.gov/sites/production/files/2016-09/documents/climate-change-az.pdf)

<sup>31</sup> Arizona Republic. 2018. *Study: Climate change could transform Arizona's forests, deserts, worsening drought and fire*. September 1. [azcentral.com/story/news/local/arizona-environment/2018/09/01/climate-change-could-transform-arizona-forests-deserts-environment-study/1148294002/](http://azcentral.com/story/news/local/arizona-environment/2018/09/01/climate-change-could-transform-arizona-forests-deserts-environment-study/1148294002/)

<sup>32</sup> Electric Vehicle Cost-Benefit Analysis: Plug-in Electric Vehicle Cost-Benefit Analysis: Arizona. December 2018. [mjbradley.com/sites/default/files/AZPEVCBAnalysisFINAL04dec18.pdf](http://mjbradley.com/sites/default/files/AZPEVCBAnalysisFINAL04dec18.pdf)

<sup>33</sup> SWEEP. 2019. *Electric Vehicles in Arizona: Economic Benefits*. [swenergy.org/pubs/electric-vehicles-in-arizona-economic-benefits-fact-sheet](http://swenergy.org/pubs/electric-vehicles-in-arizona-economic-benefits-fact-sheet)

Therefore, additional off-peak charging by EVs may help to reduce rates for all utility customers. Managed EV charging may also have the potential to assist in aligning load with solar production, as EVs can be charged during the day (when there is excess solar production). Some EV applications, like electric school buses and managed workplace charging, may be particularly well suited for this purpose.

**Q. Has the potential for EVs to lower electricity rates been studied in Arizona?**

A. Yes. In 2018, SWEEP and WRA engaged M.J. Bradley & Associates to conduct a cost-benefit analysis of increased EV deployment in Arizona.<sup>34</sup> According to that study, managed off-peak charging results in far greater financial savings to ratepayers than baseline charging or unmanaged charging. Indeed, under a high EV adoption scenario with managed off-peak charging, the average Arizona household could realize approximately \$176 in annual utility bill savings in 2050 (nominal dollars) due to managed vehicle electrification. Increased EV deployment will bring other benefits to Arizonans as well including:

- \$2.6 billion in reduced annual vehicle operating costs;
- \$300 million in reduced costs of complying with future carbon reduction regulations; and
- \$70 million in the value of reduced NOx emissions.

This issue has also been studied in a number of states. In each of these examinations, the conclusion has been that there is the potential for significant system-wide benefits from widespread EV adoption. For example, a 2017 study of EV adoption in Colorado by the consulting firm M.J. Bradley & Associates found that for every additional EV added, utility customers in aggregate receive \$630 in benefit and that if Colorado achieves the levels of EV adoption called for in the state EV plan by 2030, utility customers as a whole will see \$50 million a year in electric bill savings due to this downward pressure on rates.<sup>35</sup> A similar analysis in Minnesota found that high levels of EV adoption would exert downward pressure on electric rates, reducing the typical customer bill by \$171 per

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<sup>34</sup> Electric Vehicle Cost-Benefit Analysis: Plug-in Electric Vehicle Cost-Benefit Analysis: Arizona. December 2018. [mjbradley.com/sites/default/files/AZPEVCBAnalysisFINAL04dec18.pdf](http://mjbradley.com/sites/default/files/AZPEVCBAnalysisFINAL04dec18.pdf)

<sup>35</sup> Electric Vehicle Cost-Benefit Analysis: Plug-in Electric Vehicle Cost-Benefit Analysis: Colorado. April 2017. [mjbradley.com/sites/default/files/CO\\_PEVCB\\_Analysis\\_FINAL\\_13apr17.pdf](http://mjbradley.com/sites/default/files/CO_PEVCB_Analysis_FINAL_13apr17.pdf)

1 year by 2050.<sup>36</sup> An analysis by E3 in Ohio found that each additional EV would bring a  
2 ratepayer net benefit of \$1,470 under a high adoption scenario.<sup>37</sup>

3 **Q. Has the Commission adopted a policy statement on EVs?**

4 A. Yes. In 2019, the Commission approved two EV policy statements.<sup>38</sup> These policy  
5 statements encourage EV use, innovative rate designs, and charging infrastructure  
6 development that will improve air quality, benefit public health, and lower utility bills for  
7 all Arizonans. On EV rate design, the Commission policy specifically encourages utilities  
8 to:

- 9 • “Develop and propose innovative rate designs and load management strategies  
10 applicable to EV charging.”
- 11 • “Propose rate design tariffs and load management strategies that incentivize  
12 customers to charge vehicles during off-peak hours.”
- 13 • “Develop optional rate design tariffs and technology-based load management  
14 strategies for workplace, fleet charging, and electrified mass transit that  
15 encourage light, medium, and heavy-duty vehicle charging at times that would  
16 improve the integration of variable resources and the electric systems  
17 operational flexibility.”
- 18 • “Propose rate design tariffs and technology-based load management strategies  
19 that alleviate or address demand charges and other issues faced when deploying  
20 DC fast charging stations.”

21 **Q. Please summarize your recommendation related to residential EV rate design.**

22 A. I recommend the ACC require APS to adopt a super off-peak period for the TOU-E rate  
23 offering to encourage EV charging during super off-peak periods. Alternatively, APS could  
24 also implement a stand-alone rate option for EV customers with a similar design, which  
25 would allow the TOU-E rate option to continue as designed.

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<sup>36</sup> Electric Vehicle Cost-Benefit Analysis: Plug-in Electric Vehicle Cost-Benefit Analysis: Minnesota. July 2018. [mjbradley.com/sites/default/files/MN%20PEV%20CB%20Analysis%20FINAL%2015aug18.pdf](http://mjbradley.com/sites/default/files/MN%20PEV%20CB%20Analysis%20FINAL%2015aug18.pdf)

<sup>37</sup> Cost-Benefit Analysis of Plug-in Electric Vehicle Adoption in the AEP Ohio Service Territory. April 2017. [ethree.com/wp-content/uploads/2017/10/E3-AEP-EV-Final-Report-4\\_28.pdf](http://ethree.com/wp-content/uploads/2017/10/E3-AEP-EV-Final-Report-4_28.pdf)

<sup>38</sup> Arizona Corporate Commission Staff Policy Statement for Electric Vehicles, Electric Vehicle Infrastructure, and the Electrification of the Transportation Sector in Arizona. January 16, 2019. Docket No. RU-00000A-18-0284, Decision No. 77044. [docket.images.azcc.gov/0000195197.pdf](http://docket.images.azcc.gov/0000195197.pdf); Electric Vehicle Implementation Plan. In the Matter of Possible Modifications to the Arizona Corporate Commission’s Energy Rules. July 19, 2019. Docket No. RU-00000A-18-0284, Decision No. 77289. [docket.images.azcc.gov/0000199128.pdf](http://docket.images.azcc.gov/0000199128.pdf)

1 **III. THE APS PROPOSED INCREASE TO THE BSC IS NOT COST**  
2 **BASED OR IN THE PUBLIC INTEREST**

3 **Q. What is a BSC?**

4 A. A BSC is a fixed fee on a customer bill that is generally assessed on a monthly basis. It is  
5 also known as a customer charge or fixed charge. A BSC is the minimum amount of  
6 revenue a utility will recover from a customer, regardless of power consumption.

7 **Q. Please describe the APS proposal on the BSC.**

8 A. For the residential class, APS is proposing an increase in base revenues of \$38.9 million  
9 (not including the adjustor transfer), representing a 2.24% increase.<sup>39</sup> APS is also proposing  
10 an increase to BSCs for all rate schedules. The increase varies by rate class but is  
11 approximately a 2.5% increase for all residential and general service rate options, meaning  
12 APS is proposing to collect the entirety of its proposed revenue increase through increases  
13 to the BSC (the Company will also increase revenue collection in riders for an overall  
14 projected net increase of 5.6%). Table 3 shows the current and proposed BSCs for all  
15 residential rates, excluding solar options. The residential BSCs vary based on rate schedule.

16 *Table 3. APS Residential Rate Schedule Current and Proposed BSCs*

Rate Schedule	Current	Proposed	Change (%)
R-XS	\$ 9.87	\$ 10.11	2.43%
R-Basic	\$ 14.79	\$ 15.15	2.43%
R-Basic Large	\$ 19.74	\$ 20.19	2.28%
TOU-E	\$ 12.81	\$ 13.11	2.34%
R-2	\$ 12.81	\$ 13.11	2.34%
R-3	\$ 12.81	\$ 13.11	2.34%
R-Tech	\$ 14.79	\$ 15.15	2.43%

17 **Q. Does this table show all proposed increases to the BSC?**

18 A. No. This table does not include the residential distributed solar rates.

19 **Q. How does APS justify the proposed increases to the residential BSC?**

20 A. In its application, the Company offers no justification for collecting the entire proposed  
21 new residential revenue increase in higher BSCs. APS points to additional investments in  
22 the Ocotillo Modernization Project, the SCR at Four Corners, low income bill assistance,  
23 changes to depreciation rates, and other expenses as the basis for its revenue increase.<sup>40</sup>

<sup>39</sup> Schedule H-1, page 1 of 1.

<sup>40</sup> Arizona Public Service, Application, Docket No. E-01345A-19-0236, page 2.

1 **Q. Do you agree with the APS BSC proposal?**

2 A. No. I disagree with the proposed BSC levels for all residential rates and also with the  
3 recovery of all proposed revenue increases through the BSC. None of the proposed revenue  
4 increases are customer related costs. The prior calculation of the BSC also included several  
5 cost categories that were not customer related costs. A review of the APS approach to cost  
6 classification shows the Company is including several categories of costs that should not  
7 be classified as customer related or included in the BSC.

8 **Q. What categories of costs are generally included in a BSC?**

9 A. A BSC should typically only include customer related costs. Customer related costs are  
10 generally defined as the “operating and capital costs found to vary with the number of  
11 customers regardless, or almost regardless, of power consumption.”<sup>41</sup> These costs  
12 generally include the meter, service drop, and billing and collection costs. Limiting  
13 customer related costs to the meter, service drop, and billing/collection costs is a cost-based  
14 approach that ensures each customer is only charged a monthly fee for the costs they are  
15 causing. If costs that are not directly customer related are included and recovered in a BSC,  
16 some customers will pay more than the costs they cause while others will pay less.

17 **Q. Does APS agree with your definition of customer related costs?**

18 A. Yes. Company witness Snook agrees that customer related costs should be limited to those  
19 that vary with the number of customers on the system. In direct testimony, Mr. Snook  
20 defined cost classification as “the process of determining the factor or factors that drive the  
21 magnitude of the cost.” Mr. Snook went on to state that “if a cost is driven by the number  
22 of customers taking service on the APS system irrespective of either the kW demand or  
23 kWh energy, it is classified as customer.”<sup>42</sup>

24 **Q. Is APS including costs in the proposed BSC that are not customer related?**

25 A. Yes. I calculated the BSC for the residential class using data from the Company’s cost of  
26 service study, including the Company’s proposed revenue changes and capital structure.  
27 My analysis shows the BSC should be \$8.03 per month. Exhibit BJB-7 shows the  
28 breakdown of this analysis. A comparison of the Company’s cost of service study with my  
29 calculation shows the Company is including additional rate base items, which are most

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<sup>41</sup> Bonbright, James C. 1961. *Principles of Public Utility Rates*. Columbia University Press. p. 347.

<sup>42</sup> Snook Direct at page 9, lines 13-21.

likely distribution plant costs in its BSC. The Company is also including additional expenses that are substantially higher than the customer related expenses that are included in my calculation.

**Q. How is a basic service charged typically developed?**

A. A critical component of cost of service ratemaking is the determination of what costs are “customer related” and should be collected through the BSC. This involves classification of utility costs by account to either demand, energy, or customer. Costs that are defined as customer related are classified as customer costs. The sum of all customer related revenue requirements is then divided by the total number of bills for the test year to develop the BSC.

**Q. Do you agree with the inclusion of distribution plant costs in the BSC?**

A. The only distribution plant that should be included in a BSC is the cost of meters (FERC account 370) and services (FERC account 369).<sup>43</sup> Services refers to the costs of the service drop or line that goes from the distribution pole to the customer’s home. Other utilities in Arizona (TEP and UNS) have proposed collection of other distribution plant costs in the BSC, including costs of shared infrastructure like poles, wires, and transformers.<sup>44</sup> None of these costs vary directly with the number of customers on the system and should not be classified as customer related.

**Q. Does APS agree?**

A. APS agrees that distribution plant costs are generally not customer related. According to Company witness Snook, “distribution plant is generally designed to meet an individual customer class’s peak load.”<sup>45</sup>

**Q. Does the Company’s proposed change in the BSC better align rate design with cost causation?**

A. No, it does not. The proposed changes to the BSC will over collect costs from some customers and under collect them from others. Distribution plant costs are caused by

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<sup>43</sup> FERC defines Services Account 369 as “the cost installed of overhead and underground conductors leading from a point where wires leave the last pole of the overhead system or the distribution box or manhole, or the top of the pole of the distribution line, to the point of connection with the customer’s outlet or wiring” and Meters Account 370 as “the cost installed of meters or devices and appurtenances thereto, for use in measuring the electricity delivered to its users, whether actually in service or held in reserve.”

<sup>44</sup> See Docket Nos. E-04204A-15-0142 (UNS Electric) and E-01933A-19-0028 (Tucson Electric Power).

<sup>45</sup> Snook Direct at page 12, lines 6-8.

1 numerous customers with diverse characteristics. To recover these costs evenly among all  
2 residential customers is not cost based and should be rejected.

3 **Q. Are there other negative effects of collecting a large amount of fixed costs in a fixed**  
4 **customer charge?**

5 A. Yes, there are several negative effects of high BSCs. High BSCs reduce customer control  
6 of bills, reduce the incentive to engage in energy efficiency behaviors and programs, have  
7 a disproportionate effect on low-income customers, and will lead to higher consumption  
8 because APS is suppressing the volumetric price due to higher revenue collection in BSC.  
9 I expand on each of these points below.

10 **Q. Please describe how higher BSCs reduce customer control of bills.**

11 A. In setting electric rates, APS must collect a necessary level of revenue per customer to  
12 recover its cost of service. Revenue may be collected in volumetric rates or a fixed charge  
13 (the BSC). The fixed charge is unavoidable and must be paid, regardless of the level of  
14 electric consumption. The volumetric rate revenue is collected based on consumption. Rate  
15 design that emphasizes lower (cost based) BSCs allow customers greater control of bills  
16 because more revenue must be collected in the volumetric (controllable) part of the  
17 customer bill. As the rise in customer defaults and late payments increase, customers will  
18 need greater control of bills to maintain service.

19 **Q. Please describe how higher BSCs discourage investment in energy efficiency**  
20 **technologies and behavior.**

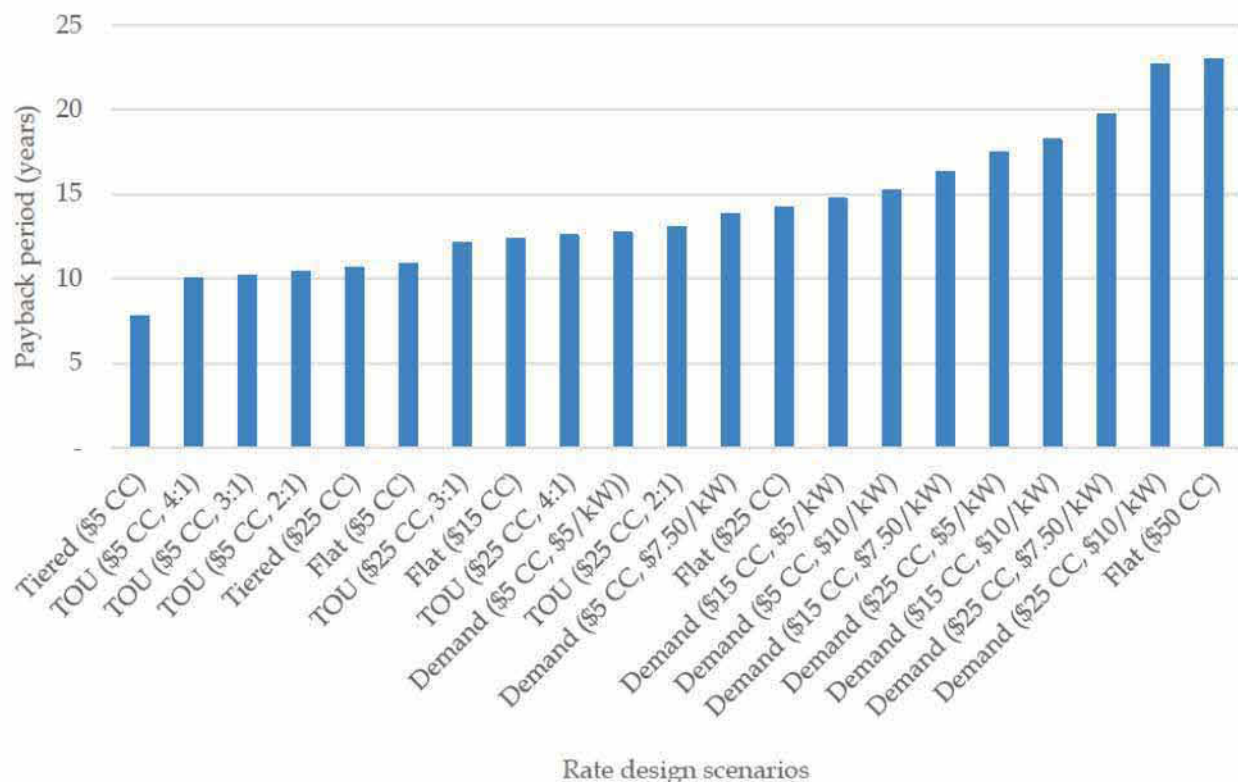
21 A. The APS proposal to collect more costs in BSCs than is justified by cost causation results  
22 in lower volumetric rates. Lower volumetric rates increase payback periods for energy  
23 efficiency and distributed generation technologies, discouraging investment in these  
24 beneficial technologies. Lower volumetric electricity prices also send a price signal to  
25 customers to increase consumption, which drives higher system costs and peak demand.

26 **Q. How significant are the rate design changes to payback periods for energy efficiency**  
27 **investments?**

28 A. Rate design can have a significant effect on payback periods for energy efficiency. The  
29 primary reason customers engage in energy efficiency programs is to save money on  
30 electric bills. Bill savings occur when customers make investments in energy efficient  
31 technologies or change behaviors to reduce consumption. Rate design significantly alters  
32 the payback periods for these investments. A 2017 study by the American Council for an

Energy Efficient Economy included an analysis on various rate designs and the payback period of attic insulation.<sup>46</sup> This analysis was based on data from the APS Technical Resource Manual (“TRM”) and showed differences in payback periods for 20 different rate design scenarios based on changes in BSCs, TOU rates, tiered rates, and demand charges. Figure 5 shows the results of this analysis.

Figure 5. Payback periods in years under 20 rate design scenarios.<sup>47</sup> CC = Customer charge. TOU = Time-of-use rate. The ratios shown are the on- to off-peak ratios for time-of-use volumetric energy rates.



As Figure 5 shows, the scenarios with the longest payback periods are those with the highest BSCs (referred to as customer charges or CC). The graphic shows the results for one measure, attic insulation, but the study shows the results for over twenty measures. All showed similar results: higher BSCs result in longer payback periods and higher payback periods discourage customers from investing in energy efficiency.

<sup>46</sup> Baatz, B. 2017. *Rate Design Matters: The Intersection of Residential Rate Design and Energy Efficiency*. American Council for an Energy Efficient Economy.

[aceee.org/sites/default/files/publications/researchreports/u1703.pdf](https://aceee.org/sites/default/files/publications/researchreports/u1703.pdf)

<sup>47</sup> *Ibid.*

1 **Q. Please describe the impact of higher BSCs on low-income customers.**

2 A. As discussed above, higher BSCs reduce customer control of bills because they increase  
3 the portion of the bill that is fixed. This is especially true for low-income customers who  
4 already face difficulties paying electric bills and need greater control of bills to avoid  
5 defaults and late payments. Increasing the BSC also diminishes rewards for low-income  
6 customers investing in energy efficiency. It is already difficult enough to deliver  
7 meaningful, cost-effective efficiency to low-income customers; this increase makes it even  
8 harder.

9 **Q. Please explain how the APS BSC proposal will lead to higher consumption.**

10 A. In short, customers respond to price signals, including electric rates. Higher rates lead to  
11 reduced consumption while lower rates lead to increased consumption. By shifting revenue  
12 recovery to fixed charges (the BSC), volumetric rates are reduced. Below, I will explain  
13 further with empirical research.

14 **Q. What is price elasticity?**

15 A. Price elasticity is an economic measure of how a consumer responds to changes in prices.  
16 For most goods and services, customers consume less when prices are higher and more  
17 when prices are lower. The changes in behavior and consumption pattern vary in the short  
18 and long term as well. For example, when gasoline prices are low, consumers tend to travel  
19 more in the short term and buy less fuel-efficient cars in the long term. In the short term,  
20 consumers have fewer options to respond to higher prices, but in the long term, consumers  
21 have more options because they can alter larger purchase behavior and even alter where  
22 they live to reduce commuting costs.

23 **Q. How does price elasticity relate to electricity consumption?**

24 A. Electricity is no different than many other commodities. Customers change behaviors and  
25 purchasing habits based on changes in prices. Price elasticity for electricity has been  
26 studied for over 50 years in the United States. These studies consistently show that  
27 customers reduce electric consumption when prices are high and increase consumption  
28 when prices are low.

One commonly cited study was conducted by the Electric Power Research Institute (“EPRI”) in 2008.<sup>48</sup> This study analyzed the price responsiveness of residential electricity consumers to changes in volumetric electricity prices. EPRI has low, high, and mean estimates of the price responsiveness of residential consumers to changes in retail electricity prices both in the near term and in the long-run.

EPRI’s price response estimates come from a review of several studies examining how electricity customers change their consumption in reaction to changes in prices. These studies used actual data on electricity prices and usage by residential customers. The EPRI paper reports a range of estimates of how sensitive consumers are to changes in prices from these studies. The short-run mean estimate of this sensitivity, known in economic terms as elasticity, was found to be -0.3, indicating that a 1% increase in volumetric electricity rates would result in a 0.3% decrease in consumption. In this context, the “short-run” is not precisely defined but can be taken to cover a range of up to 5 years. In the long-run, consumers have more opportunities to change their habits and behavior as well as to respond to higher prices by investing in more energy-efficient appliances as the appliances age and need to be replaced. Reflecting this fact, long-run elasticities are typically higher than their short-run counterparts. In this case, EPRI found a mean long-term elasticity of -0.9, indicating that a 1% increase in volumetric electricity rates would reduce consumption by 0.9%.

**Q. Are there other studies that show customers respond to changes in electricity prices?**

A. Yes, there are many studies that show people respond to changes in electric rates. Most recently, the Department of Energy sponsored a series of studies on consumer behavior, rate design, and smart technologies. The studies showed consumers responded to higher prices by shifting demand to lower price periods or reducing overall consumption when placed on TOU rates. The peak period demand reductions were far less on average for the lowest peak to off-peak price ratios (6% for treatments with a peak to off-peak price ratio less than 2:1) than for the highest price ratios (18% for treatments with a peak to off-peak

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<sup>48</sup> Electric Power Research Institute. 2008. *Price Elasticity of Demand for Electricity: A Primer and Synthesis*. [epri.com/abstracts/Pages/ProductAbstract.aspx?ProductId=000000000001016264](http://epri.com/abstracts/Pages/ProductAbstract.aspx?ProductId=000000000001016264)

price ratio greater than 4:1).<sup>49</sup> The peak to off-peak ratio is the ratio of the energy price for the two periods. Thus, the research shows the higher peak demand reductions occurred when the difference between the on and off-peak price was higher.

**Q. Please describe the relevance of price elasticity of demand to the current APS rate case proposals.**

A. APS is proposing several rate designs that will increase overall consumption. APS is proposing higher BSCs, which will reduce the volumetric electric prices. As many previous price elasticity studies show, the lower prices will lead to increased consumption. The APS subscription pricing pilot removes the price signal to customers entirely, which will also increase overall consumption. The increases in overall consumption driven by these proposals will lead to higher system costs because increased overall consumption will require additional investments by APS over time to meet growing load. The higher overall consumption will also lead to higher air emissions from increased output on the APS system.

**Q. How will the SWEEP/WRA proposals decrease overall consumption?**

A. The decades of price elasticity research have demonstrated decreases in consumption when electricity prices are higher. To illustrate this effect based on empirical research, I examined how the lower BSC would decrease consumption for customers on the R-Basic rate. I redesigned the R-Basic rate using the BSC based on the basic customer method. My calculated BSC of \$8.03 is nearly half of the proposed APS BSC of \$15.15 per month for the R-Basic rate. When the revenue previously collected in the higher BSC is moved to the energy charge, the price per kWh increases from \$0.127 to \$0.137 per kWh, an increase of 8.5%.

To estimate the change in consumption in the short-run, I used the EPRI price elasticity result of -0.3. This elasticity implies that for every 1% increase in price, customer demand will decrease by 0.3%. For an 8.5% increase in the energy price, we would expect a decrease in consumption of 2.56%. For the customers on R-Basic moving from APS's proposed rate to the SWEEP/WRA proposed rate, this would mean a decrease of 26,732 MWh of energy sales. The decrease in sales not only decreases costs related to serving the

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<sup>49</sup> See United States Department of Energy. 2016. *Customer Acceptance, Retention, and Response to Time-Based Rates from the Consumer Behavior Studies*. Smart Grid Investment Grant Program. [energy.gov/sites/prod/files/2015/06/f24/ARRA-CBS\\_interim\\_program\\_impact\\_report\\_June2015.pdf](https://energy.gov/sites/prod/files/2015/06/f24/ARRA-CBS_interim_program_impact_report_June2015.pdf)

1 additional load, but also decreases harmful emissions because of decreased generation.  
2 Conversely, for customers moving from the SWEEP/WRA proposed rate to APS's  
3 proposed rate, this would mean an additional 26,732 MWh of energy sales.

4 **Q. Can you estimate the potential increase in emissions from the estimated change in**  
5 **consumption from a higher BSC and lower volumetric rates?**

6 A. Yes. All generators in Arizona report air emissions for several pollutants to the  
7 Environmental Protection Agency ("EPA"). The EPA publishes emissions rates (rate of air  
8 emissions per unit of energy produced) for all fifty states in the Emissions & Generation  
9 Resource Integrated Database ("eGRID").

10 **Q. What is eGRID and how does its source air emissions data?**

11 A. According the EPA, eGRID is a comprehensive inventory of environmental attributes of  
12 electric power systems. The preeminent source of air emission data for the electric power  
13 sector, eGRID is based on available plant-specific data for all U.S. electricity generating  
14 plants that provide power to the electric grid and report data to the U.S. government. eGRID  
15 uses data from the Energy Information Administration (EIA) Forms EIA-860 and EIA-923  
16 and EPA's Clean Air Markets Program Data. Emission data from EPA are carefully  
17 integrated with generation data from EIA to produce useful values like pounds of emissions  
18 per megawatt-hour of electricity generation (lb/MWh), which allows direct comparison of  
19 the environmental attributes of electricity generation. eGRID also provides aggregated data  
20 by state, U.S. total, and by three different sets of electric grid boundaries (i.e., balancing  
21 authority area, NERC region, and eGRID subregion).<sup>50</sup> eGRID publishes state level  
22 emissions rates for criteria air pollutants. I used the emissions rates (lbs/MWh) and the  
23 increased generation to estimate the increased emissions.

24 **Q. What are the results of this analysis?**

25 A. The results show significant increases in air emissions from small increases in  
26 consumption. Table 4 shows the increase in air pollution for the increase in sales driven by  
27 higher BSCs for the R-Basic rate for carbon dioxide ("CO<sub>2</sub>"), nitrogen oxide ("NO<sub>x</sub>"), and  
28 sulfur dioxide ("SO<sub>2</sub>"). This change in emissions is based on the increase of 26,732 MWh  
29 calculated above.

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<sup>50</sup> United States Environmental Protection Agency. "Emissions and Generation Resource Integrated Database (eGRID) Questions and Answers. Accessed on July 19, 2020. [epa.gov/energy/emissions-generation-resource-integrated-database-egrid-questions-and-answers](https://www.epa.gov/energy/emissions-generation-resource-integrated-database-egrid-questions-and-answers)

Table 4. Increase in air pollution for carbon dioxide, nitrogen oxide, and sulfur dioxide

Pollutant	Emissions rate (lbs/MWh)	Increase in Pollution (tons)
CO <sub>2</sub>	1211.3	16,190
NO <sub>x</sub>	0.6	8.0
SO <sub>2</sub>	0.3	4.0

**Q. WHAT ARE THE ENVIRONMENTAL IMPLICATIONS OF THE INCREASE IN AIR POLLUTION?**

A. As the analysis shows, even a small increase in consumption produces large increases in power plant emissions. Power plant emissions, including CO<sub>2</sub>, NO<sub>x</sub>, and SO<sub>2</sub> impose harmful effects on the natural environment and human health. All three of these emissions impose societal costs because of these harmful effects. Harmful effects of these air pollutants include, but are not limited to, irritation of human respiratory systems,<sup>51</sup> fine particles that reduce visibility,<sup>52</sup> and higher temperatures which increase prevalence of heat waves.

**Q. Would the results be similar for the other residential rate schedules?**

A. Yes. Customers on R-Basic only represent 8% of the test year MWh sales for APS. The BSC is incorrectly calculated for all rate schedules, which artificially suppresses the volumetric energy prices, leading to higher consumption.

**Q. Please summarize your conclusions and recommendations regarding the APS BSC proposal.**

A. The APS residential BSC proposal should be rejected by the Commission because it:

- is not cost based;
- reduces customer control of bills;
- reduces customer incentives to invest in energy efficiency and distributed generation;
- harms low-income customers who need greater control of bills to avoid defaults and late payments; and

<sup>51</sup> United States Environmental Protection Agency. "Nitrogen Dioxide (NO<sub>2</sub>) Pollution," [epa.gov/no2-pollution](https://www.epa.gov/no2-pollution)

<sup>52</sup> United States Environmental Protection Agency. "Sulfur Dioxide (SO<sub>2</sub>) Pollution," Accessed on October 4, 2020. [epa.gov/so2-pollution/sulfur-dioxide-basics#effects](https://www.epa.gov/so2-pollution/sulfur-dioxide-basics#effects)

- leads to higher consumption because APS is suppressing the volumetric price due to higher revenue collection in BSC.

The Commission should adopt a BSC developed using the basic customer method. My calculation of the BSC using this method results in a monthly BSC of \$8.03. The Commission should adopt \$8.03 for all residential rate options and require APS to refile residential rates with the additional revenue reflected in volumetric rates.

#### **IV. THE APS SUBSCRIPTION RATE PILOT PROPOSAL IS NOT IN THE PUBLIC INTEREST AND SHOULD BE REJECTED**

**Q. Please describe the APS subscription rate pilot proposal.**

A. APS is proposing to conduct a pilot in which a randomly selected group of 5,000 customers will be placed on a subscription rate option. Under this option, APS will bill these customers a fixed monthly amount, no matter how much electricity the customers use in the month. The monthly bill for the two-year pilot period would be based on the previous 12 months of usage, calculated based on proposed rates (not historic bills). 2,500 of the 5,000 customers will be the “control” group of the experiment, meaning these customers will not receive any “treatments,” which is a utility-controlled demand response device, as part of the experiment. The remaining 2,500 customers will need to have a WIFI thermostat installed, which will be controllable by APS. The Company is also proposing to bill customers without WIFI thermostats an additional fee of 5% to cover the expected increases in consumption.<sup>53</sup>

**Q. Do you support the APS subscription rate pilot program?**

A. No, I do not. I have significant concerns with the pilot program. Under this proposal, APS would bill customers using a flat bill approach, meaning customers would receive no price signals regarding how their consumption influences the APS costs to serve that customer. Because of the complete lack of a price signal, customers would essentially be on an “all you can eat” rate plan, meaning they could use as much electricity at any point in the day throughout the month with no financial repercussions. APS would have limited control of consumption because the Company is only proposing to control thermostats for half of the customers.

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<sup>53</sup> Hobbick Direct at page 6-8.

1           The proposed subscription rate pilot program also violates critical principles of rate  
2 design, specifically the fair-cost apportionment objective and optimum-use or consumer  
3 rationing objective. According to Professor James Bonbright, the author of Principles of  
4 Public Utility Rates, the fair-cost apportionment objective “invokes the principle that the  
5 burden of meeting the total revenue requirements must be distributed fairly among the  
6 beneficiaries of that service.”<sup>54</sup> The subscription rate pilot would charge customers a flat  
7 amount for consumption, regardless of usage, meaning these customers would likely be  
8 charged less than other customers for the same service, which is a violation of the fairness  
9 principle. The optimum-use or consumer rationing objective requires that “rates are  
10 designed to discourage wasteful use of public utility services while promoting all use that  
11 is economically justified in view of the relationships between costs incurred and benefits  
12 received.”<sup>55</sup> The subscription rate pilot program would encourage wasteful use of  
13 electricity because it does not send customers actionable price signals regarding when and  
14 how to consume electricity.

15 **Q. Why do you believe customers would consume more electricity under the**  
16 **subscription rate pilot program?**

17 A. There are two primary reasons of why I think overall consumption would increase for  
18 customers on the subscription rate pilot program. First, evidence from other utilities  
19 indicates a significant increase in consumption under similar rate designs. Second, APS is  
20 expecting large increases in consumption that will not be offset by utility controlled smart  
21 thermostats. I will expand on both of these points.

22 **Q. Please describe the evidence from other utilities on this approach to billing**  
23 **customers.**

24 A. There are other utilities offering flat bill options elsewhere in the United States. Georgia  
25 Power is the most cited example. Georgia Power has offered a flat bill option to residential  
26 customers for decades.<sup>56</sup> The customer’s monthly bill is based on the average of the  
27 previous 12 months, but also includes an additional 10% fee to cover increased  
28 consumption. The 10% is not included in the Georgia Power’s revenue requirement and

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<sup>54</sup> Bonbright, J. 1961. *Principles of Public Utility Rates*. Columbia University Press: New York and London. Page 292.

<sup>55</sup> *Ibid.*

<sup>56</sup> Georgia Power FLATBILL SCHEDULE, “FLAT-5.” [georgiapower.com/content/dam/georgiapower/pdfs/residential-pdfs/residential-rate-plans/FLAT-5.pdf](http://georgiapower.com/content/dam/georgiapower/pdfs/residential-pdfs/residential-rate-plans/FLAT-5.pdf)

any financial losses or gains are absorbed by the utility. According to the Georgia Power 2018 FERC Form 1, over 12% of residential customers were on a flat bill. A review of the past four years of data shows these customers consistently use approximately 20% more electricity than customers on the standard residential rate. Table 5 shows the annual usage for the two customer groups over the four-year period.

Table 5. Georgia Power annual usage for residential standard and flat bill customers 2015 through 2018.  
Source: Georgia Power FERC Form 1 2015-2018.

Year	Annual usage (kWh)		Difference
	Residential	Flat Bill Residential	
2015	12,403	14,800	19.3%
2016	12,418	15,016	20.9%
2017	11,542	14,065	21.9%
2018	12,466	15,126	21.3%

**Q. Are you aware of other utilities offering flat bill?**

A. Yes. Oklahoma Gas and Electric also offers a flat bill option.<sup>57</sup> A review of the past four years shows a similar result. Customers on flat bill use substantially more electricity than customers who are not. In 2015 the difference was 10% but increased to nearly 15% by 2017. The difference is less substantial than for Georgia Power, but still significant. Table 6 shows the results of that review.

Table 6. Oklahoma Gas and Electric annual usage for residential standard and flat bill customers 2015 through 2018. Source: Oklahoma Gas and Electric FERC Form 1 2015-2018.

Year	Annual usage (kWh)		Difference
	Residential	Guaranteed Flat Bill	
2015	12,607	13,868	10.0%
2016	12,457	14,063	12.9%
2017	11,849	13,607	14.8%
2018	12,930	14,742	14.0%

**Q. APS is planning to require that customers have a smart thermostat as a condition of participating in the pilot, which will supposedly offset the increases in consumption. Will this alleviate your concerns about increased consumption?**

<sup>57</sup> Oklahoma Gas and Electric. Rate Options. [oge.com/wps/portal/oge/my-account/billing-payments/rate-options/](http://oge.com/wps/portal/oge/my-account/billing-payments/rate-options/)

1 A. No, definitely not. APS currently includes smart thermostats in its demand side  
2 management (“DSM”) program. For residential customers, the Company assumes annual  
3 savings of 83 kWh, which is less than one percent (0.68%) of average annual  
4 consumption.<sup>58</sup> The addition of utility control during specific events will increase the  
5 energy savings, but it is highly unlikely the utility control will offset the increased  
6 consumption. Furthermore, APS stated that customers will be able to override utility  
7 control of the thermostat with no penalty, reducing the likelihood of higher energy  
8 savings.<sup>59</sup>

9 **Q. In your opinion, why would APS offer a rate option in which it would under collect**  
10 **revenue relative to usage?**

11 A. APS, like other investor owned utilities, increases revenue through customer growth. The  
12 growth can occur in the number of customers, but also in total usage and peak demand for  
13 existing customers. Growth in peak demand allows APS to increase investments in  
14 distribution and generation capacity to meet the new demand. These new investments allow  
15 APS to continue to grow its rate base over time, ensuring returns to shareholders. The  
16 substantial growth in customer usage shown in other utilities with flat bill options would  
17 allow APS these opportunities.

18 **Q. Are there other implications to the subscription rate pilot program beyond the**  
19 **increases in overall consumption?**

20 A. The increases in overall consumption would drive larger investments in new capacity to  
21 meet demand growth but would also require APS to generate additional electricity to meet  
22 the demand. The additional electricity would increase costs for all customers but would  
23 also increase harmful emissions from increased power plant output. The APS generation  
24 fleet still relies on coal and natural gas, which produce CO<sub>2</sub>, NO<sub>x</sub>, SO<sub>2</sub>, and particulate  
25 matter. All of these pollutants harm the natural environment and human health. I elaborated  
26 on how increased consumption drives increased air pollution in an earlier discussion on  
27 increased BSCs.

28 **Q. But APS is proposing the subscription rates as a pilot. Why would you object to a**  
29 **limited pilot to gather information and better understand customer response to**  
30 **subscription rate options?**

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<sup>58</sup> See Exhibit BJB-8 APS Response to SWEEP DR 2.2.

<sup>59</sup> See Exhibit BJB-9 APS Response to SWEEP DR 1.23.

1 A. It would be a wasteful use of ratepayer dollars to undertake a pilot program that would  
2 unnecessarily increase consumption, driving higher system costs and air pollution in APS's  
3 service territory. APS residential customers have already been subjected to enough  
4 experimentation over the last three years under the rollout of its last rate design.

5 **Q. Do you have additional recommendations regarding the subscription pricing pilot**  
6 **program?**

7 A. Yes. Instead of implementing the Subscription Rate Pilot Program, APS should expand  
8 energy efficiency and demand response opportunities for all customers and couple these  
9 opportunities with rate design options that send customers actionable price signals, like  
10 APS's existing TOU rates. Coupling energy efficiency and demand response with time  
11 varying rates will allow APS to maximize customers' responses to rates, which will lower  
12 system costs and harmful emissions.

13 **V. THE COMMISSION SHOULD AUTHORIZE APS TO COLLECT**  
14 **\$65 MILLION ANNUALLY IN BASE RATES FOR DSM**  
15 **PROGRAMS**

16 **Q. Why is it in the public interest to increase electric energy efficiency investment?**

17 A. Increased electric energy efficiency investment is in the public interest for several reasons.  
18 Increasing energy efficiency provides substantial cost-effective benefits for all APS  
19 customers, the electric system, the economy, and the environment. Electric energy  
20 efficiency is a reliable energy resource that is less expensive than other available energy  
21 resources. Consequently, increasing energy efficiency saves consumers and businesses  
22 money through lower electric bills and the deferral of unnecessary infrastructure, resulting  
23 in lower total costs for customers. Increasing energy efficiency also reduces load growth  
24 and peak demand, diversifies energy resources, enhances the reliability of the electricity  
25 grid, reduces the amount of water used for power generation, reduces air pollution, creates  
26 jobs that cannot be outsourced, and drives local economic growth. In addition, meeting a  
27 portion of load growth through increased energy efficiency can help to relieve system  
28 constraints in load pockets. By reducing electricity demand, energy efficiency mitigates  
29 electricity and fuel price increases and reduces customer vulnerability and exposure to  
30 price volatility. Energy efficiency does not rely on any fuel and is not subject to shortages  
31 of supply or increased prices for natural gas or other fuels.

1 **Q. What have APS' recent efficiency investments accomplished?**

2 A. From 2011-2019<sup>60</sup>, APS reports that its efficiency programs:

- 3 • Provided over 43.7 million MWh of lifetime electric savings;
- 4 • Produced over 1,000 MW of peak demand savings;
- 5 • Saved over 13.6 billion gallons of water;
- 6 • Reduced harmful emissions significantly, including 19.3 million tons of CO<sub>2</sub>, 96
- 7 tons of SO<sub>2</sub>, and 1,800 tons of NO<sub>x</sub>; and
- 8 • Generated over \$1.9 billion in benefits to Arizona residents and businesses.

9 Additionally, energy efficiency has created more than 40,000 jobs across our state,  
10 including more than 28,000 in Phoenix.<sup>61</sup> These jobs pay well, are local, and are in hands-  
11 on fields like installation so they cannot be easily outsourced.

12 **Q. What kinds of efficiency programs does APS offer?**

13 A. APS offers a “portfolio” of efficiency programs for both residential and commercial  
14 customers. Specialized programs and offerings are available for all customer types  
15 including homeowners, renters, limited income customers, small businesses, schools, and  
16 large commercial and industrial customers. Programs help low-income customers with a  
17 series of home improvements, from insulation to appliance repair and replacement; help  
18 homeowners to seal leaky ductwork and fix malfunctioning HVAC units; and offer rebates  
19 to help residents buy smart thermostats and more efficient pool pumps — to name a few  
20 examples. APS was recently highlighted as one of fourteen leading utilities in a 2016  
21 national report by ACEEE entitled, “Big Savers: Experiences and Recent History of  
22 Program Administrators Achieving High Levels of Energy Savings.”<sup>62</sup>

23 **Q. Why should energy efficiency cost recovery be considered in the context of the APS**  
24 **rate case proceeding?**

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<sup>60</sup> APS Annual Demand Side Management reports filed with the Arizona Corporation Commission.

<sup>61</sup> Environmental Entrepreneurs, Energy Efficiency Jobs in America: Arizona. <https://www.e2.org/wp-content/uploads/2018/09/ARIZONA-Dist.pdf>

<sup>62</sup> Baatz, B. 2016. *Big Savers: Experiences and Recent History of Program Administrators Achieving High Levels of Energy Savings*. American Council for an Energy Efficient Economy. [aceee.org/sites/default/files/publications/researchreports/u1601.pdf](https://www.aceee.org/sites/default/files/publications/researchreports/u1601.pdf)

1 A. The Commission, in approving any order that changes or increases rates for customers,  
2 should ensure that the least expensive resource – energy efficiency – is fully pursued  
3 beforehand. Consequently, in its order on the APS rate case, the Commission should ensure  
4 that APS is on a path to continue delivering all cost-effective energy efficiency; ensure that  
5 there is adequate funding to achieve all cost-effective energy savings levels and attain the  
6 associated customer and public benefits; and treat energy efficiency as the core energy  
7 resource that it is by providing a stable, long-term cost recovery mechanism and adequate  
8 funding in base rates.

9 **Q. What should the Commission do to ensure adequate efficiency investment and**  
10 **funding?**

11 A. As a core resource meeting the real energy needs of customers at lowest cost, efficiency  
12 should be adequately funded through a stable, fully embedded funding and cost recovery  
13 mechanism as part of this case. In order to provide adequate and appropriate treatment for  
14 this core, fundamental energy and capacity resource, a total of at least \$65 million of energy  
15 efficiency program funding should be recovered in base rates. As a core resource, it is  
16 appropriate for energy efficiency cost recovery to be mostly recovered in base rates rather  
17 than in a separate adjustor mechanism. An adjustor mechanism should be used solely to  
18 true up actual expenditures versus authorized amounts collected in base rates.

19 **Q. What is the basis for the \$65 million annual recommendation?**

20 A. This amount is slightly more than the \$51.9 million budget that the Commission recently  
21 approved for APS to invest in cost effective energy efficiency programs in approving the  
22 2020 DSM Plan.<sup>63</sup> APS has collected \$66.6 million in previous years.

23 **Q. Do you recommend continuation of the demand side management adjustment**  
24 **charge?**

25 A. Yes. The demand side management adjustment charge (“DSMAC”) should continue to  
26 provide a mechanism to reconcile actual and planned spending. If APS does not spend the  
27 entire \$65 million, all unspent funds should be returned to customers on a current basis.  
28 Likewise, if the Commission authorizes APS to recover additional dollars because of  
29 increased need, APS will be able to recover additional dollars through the DSMAC until  
30 its next rate case.

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<sup>63</sup> Decision No. 77763, Docket No. E-01345A-19-0088, [docket.images.azcc.gov/0000202208.pdf](https://docket.images.azcc.gov/0000202208.pdf)

1 **Q. Do you have any other recommendations?**

2 A. Yes. In its order in the APS rate case, the Commission should also ensure that APS is on a  
3 path to meet minimum energy savings levels for the next decade.

4 **Q. What energy savings levels should APS meet, by when?**

5 A. Consistent with a proposal recently filed with the Commission that is supported by 32  
6 different consumer, faith, environmental, and business entities,<sup>64</sup> APS should commit to  
7 deliver at least 1.3% net annual savings each year from 2020-2030.

8 **VI. APS SHOULD BE ALLOWED TO EARN A RETURN ON**  
9 **ENERGY EFFICIENCY INVESTMENTS**

10 **Q. Please summarize your recommendation on how APS should recover energy**  
11 **efficiency costs in base rates.**

12 A. I recommend the Commission allow APS to rate base energy efficiency program costs and  
13 earn a return on these investments at the Commission approved rate of return. To do so,  
14 the Commission should authorize APS to book energy efficiency program costs as a  
15 regulatory asset and amortize these costs over a seven-year period.

16 **Q. Does APS currently earn a return on energy efficiency investments?**

17 A. No. APS is currently expensing most energy efficiency costs over a one-year period  
18 through the DSM surcharge and \$20 million collected through base rates.<sup>65</sup>

19 **Q. APS currently earns a performance incentive for energy efficiency. How is the**  
20 **performance incentive different than allowing APS to earn a return on energy**  
21 **efficiency investment costs?**

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<sup>64</sup> Joint Stakeholder Proposal for New Energy Rules, July 30<sup>th</sup>, 2019, Docket No. RU-00000A-18-0284.  
[docket.images.azcc.gov/E000002141.pdf](https://docket.images.azcc.gov/E000002141.pdf)

The proposal is supported by: American Council for an Energy-Efficient Economy, Arizona Faith Network, Arizona Interfaith Power and Light, Arizona Solar Energy Industries Association (AriSEIA), AZ Public Health Association, Black Mesa Water Coalition, CHISPA Arizona, Citizen's Climate Lobby, Conservative Alliance for Solar Energy (CASE), Diné C.A.R.E., E4TheFuture, Earth Justice Ministry of Unitarian Universalist Congregation of Phoenix, Elders Climate Action, Environment Arizona Research & Policy Center, Grand Canyon Trust, League of Women Voters Arizona, Natural Resources Defense Council, Oculus-Studio, Our Mother of Sorrows Catholic Church, Physicians for Social Responsibility, Sierra Club, Solar Energy Industries Association (SEIA), Solar United Neighbors, SWEEP), Sunrun, Tó Nizhóní Ání, Tucson 2030 District, Vote Solar, Western Grid Group, WRA, Yavapai Climate Change Coalition, and Solar Gain.

<sup>65</sup> In matter of the application of Arizona Public Service Company for a Ruling Relating to its 2020 Demand Side Management Implementation Plan. Decision No. 76313, Docket No. E-01345A-16-0176.

1 A. A performance incentive is a different policy than allowing a utility to earn a return on  
2 energy efficiency investments. A performance incentive is a one-time payment to a utility  
3 for achieving specific goals or requirements. This payment is generally made after the  
4 implementation of the energy efficiency programs. For APS, the performance incentive  
5 payment is calculated based on net benefits of programs, driving APS to deliver programs  
6 that produce higher net benefits. A performance incentive is not guaranteed and only  
7 awarded after a utility has invested dollars in energy efficiency programs. In contrast,  
8 allowing APS to amortize expenses over multiple years and earn a return on the  
9 unamortized balance provides APS with greater certainty that budgets are stable, puts  
10 energy efficiency investments on equal footing with other capital investments in terms of  
11 attractiveness, and reduces rate impacts.

12 **Q. Should APS maintain its performance incentive if it is allowed to earn a return on**  
13 **its investment?**

14 A. Yes. A performance incentive can still be a useful policy to motivate APS to meet specific  
15 policy goals.

16 **Q. Why should APS be allowed to earn a return on energy efficiency investments?**

17 A. APS has limited capital to invest in distribution infrastructure, customer information  
18 technology and billing systems, generation assets, and other necessary projects to provide  
19 service. The Company will logically invest in opportunities that provide the greatest return,  
20 assuming regulatory approval. Energy efficiency has been the least cost resource available  
21 to APS in recent years, but the Company has not fully invested in all cost-effective energy  
22 efficiency resources because of limited earnings opportunities and potential revenue losses  
23 from reduced sales. Allowing APS to earn a return on energy efficiency investments will  
24 increase the likelihood that the Company will invest in more cost-effective energy  
25 efficiency because it makes the earnings opportunities comparable with other system  
26 investments. Increasing investment in cost effective energy efficiency will lower costs in  
27 the short and long term.

28 **Q. Does your proposal increase the likelihood of APS inflating energy efficiency**  
29 **budgets simply to increase spending?**

30 A. Potentially. It will be important for the ACC to carefully review energy efficiency filings  
31 in a timely fashion in order to avoid wasteful spending and continue to balance the interests  
32 of APS and its customers. There is also substantial national evidence and data to draw on

1 related to specific energy efficiency program cost metrics to consider while benchmarking  
2 APS's proposals.<sup>66</sup>

3 **Q. Are there other states that allow utilities to earn a return on energy efficiency**  
4 **investments?**

5 A. Yes, there are several other states that allow utilities to earn a return on energy efficiency  
6 program investments. I am aware that New Jersey, Maryland, Illinois, Utah, and Colorado  
7 do so. Each state allows utilities to earn a return on energy efficiency investments  
8 amortized over several years. The amortization periods vary but are not significantly  
9 different. The periods include New Jersey (seven years), Maryland (five years), Utah (ten  
10 years), Colorado (eight years), and Illinois (weighted average measure life).

11 **Q. Should APS amortize the costs of efficiency over a multiple year period, like the**  
12 **other states just listed?**

13 A. Yes. There are several reasons to amortize costs over multiple years. First, this approach  
14 reduces rate impacts of energy efficiency programs because costs are collected over several  
15 years instead of one. Second, amortizing cost recovery over multiple years aligns the timing  
16 of realized benefits with costs incurred by customers. Energy efficiency investments  
17 provide energy savings for multiple years and cost recovery should be aligned with the  
18 timing of benefits provided by these programs. Finally, allowing utilities to amortize costs  
19 of energy efficiency programs provides equal and comparable cost recovery treatment to  
20 other investments.

21 **Q. Are you proposing a specific amortization period for this filing?**

22 A. Ideally, energy efficiency program costs would be amortized over a period equal to the  
23 weighted average measure life of the total portfolio, aligning the amortization period with  
24 the energy savings lifetime. This is the approach used in Illinois. However, this approach  
25 creates a different amortization period every year and could be administratively  
26 burdensome, creating disagreements on how to calculate the weighted average lifetime.  
27 For simplicity, I recommend the ACC adopt a seven-year amortization period. Seven years  
28 better aligns costs and benefits, reduces rate impacts, and moves cost recovery of energy  
29 efficiency investments comparable to supply side investments.

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<sup>66</sup> Lawrence Berkeley National Laboratory. "What It Costs to Save Energy." [emp.lbl.gov/projects/what-it-costs-save-energy/](http://emp.lbl.gov/projects/what-it-costs-save-energy/)

1 **Q. Would recovery of energy efficiency program costs in base rates decrease**  
2 **transparency for customers?**

3 A. Absolutely not. All energy resources should be treated equally in terms of disclosure.  
4 Recovering energy efficiency program costs through base rates would be consistent with  
5 the treatment of other energy resources, whose costs are not expressly identified by the  
6 current bill format.

7 **Q. Has the Commission allowed efficiency program funding to be expensed in base**  
8 **rates previously?**

9 A. Yes. In Commission Decision No. 67744, approving the settlement agreement to increase  
10 APS rates in 2005, an annual \$10 million allowance for DSM costs was approved for  
11 inclusion within base rates. In 2006, the year directly following that decision, the Company  
12 spent \$10.6 million on energy efficiency programs. Thus the \$10 million of funding in base  
13 rates equated to more than 90% of energy efficiency program expenditures in that year. In  
14 the last APS rate case, this amount was increased to \$20 million.

15 **Q. Is there other recent precedent in Arizona supporting this approach?**

16 A. Yes. As part of the 2019 Salt River Project (“SRP”) pricing proceeding, SRP decided to  
17 treat energy efficiency like other capacity resources by funding and recovering efficiency  
18 program expenses in base rates instead of through a separate adjustment rider.<sup>67</sup> For  
19 example, over the next five years, SRP will expense between \$50-\$55 million per year in  
20 base rates for its efficiency programs.

21 **Q. Would you also recommend the return on investment be adjusted based on APS**  
22 **performance in delivering energy efficiency savings?**

23 A. Yes. However, this change would need to be considered as a potential replacement for the  
24 current APS energy efficiency performance incentive. Energy efficiency performance  
25 should also be considered a key policy goal in the larger discussion of implementing a PBR  
26 mechanism for APS, which I discuss in greater detail in Section VIII of this testimony.

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<sup>67</sup> Salt River Project. Public Pricing Process. [srpnet.com/prices/priceprocess/2019/default.aspx](http://srpnet.com/prices/priceprocess/2019/default.aspx)

1 **VII. THE COMMISSION SHOULD REQUIRE APS TO RESET THE**  
2 **LFCR AND ESTABLISH AN EARNINGS TEST FOR**  
3 **RECOVERY.**

4 **Q. Please summarize the APS LFCR proposal in this case.**

5 A. APS is proposing to continue utilizing the LFCR in this case. However, according to  
6 Company witness Snook, APS is proposing to leave the lost fixed costs currently collected  
7 in the LFCR instead of resetting the mechanism to zero.<sup>68</sup> Lost fixed cost recovery  
8 mechanisms are common across the United States, but it is highly unusual to not reset the  
9 mechanism during a general rate case.

10 **Q. Please describe the LFCR.**

11 A. The LFCR was first approved by the ACC in Decision No. 73183. The mechanism was  
12 developed to address APS's lost revenues from energy efficiency and distributed  
13 generation. The mechanism was modified in Decision 74202 to expand the costs included  
14 in the LFCR.

15 **Q. Was the LFCR reset to zero following the last rate case?**

16 A. Yes. According to the Settlement Agreement, APS transferred the LFCR balance to base  
17 rates.<sup>69</sup>

18 **Q. Do you support continuation of the LFCR as proposed by APS?**

19 A. No, I do not. The LFCR is an inferior policy to full revenue decoupling. If the Commission  
20 decides to adopt a formula rate or full revenue decoupling (as SWEEP has proposed in the  
21 last several APS rate cases), the LFCR should be discontinued. However, if the ACC  
22 determines the LFCR should continue, it should be reset to zero. Resetting a lost revenue  
23 recovery rider to zero in the context of a rate case is standard practice and eliminates the  
24 potential for over recovery of authorized fixed costs because the bill determinants are also  
25 reset during a rate case.

26 **Q. Please elaborate on what you mean by the billing determinants reset to zero.**

27 A. The LFCR is currently recovering a portion of lost revenues authorized during the last APS  
28 rate case. These revenues would have otherwise been collected in volumetric rates  
29 established based on revenue requirements and billing determinants for each customer

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<sup>68</sup> Snook Direct at page 3, lines 1-5.

<sup>69</sup> Decision No. 76295. August 18, 2017. [docket.images.azcc.gov/0000182160.pdf](https://docket.images.azcc.gov/0000182160.pdf)

1 class. In a rate case, the billing determinants are based on a test year, which includes the  
2 reduced sales from energy efficiency and distributed generation for that period. When rates  
3 are established using those billing determinants, the assumed “lost revenues” are included  
4 in new rates. This is why utilities who rely on lost revenue recovery mechanisms reset these  
5 riders to zero during a base rate case. I recommend APS also reset the LFCR to zero in this  
6 case.

7 **Q. Did APS provide any justification for keeping costs in the LFCR?**

8 A. APS stated that it is proposing to keep costs in the LFCR to “ensure the estimated net bill  
9 impacts put forth in this rate case are what consumers can expect on the rate effective  
10 date.”<sup>70</sup> It sounds like APS is concerned about a messaging issue to its customers rather  
11 than avoiding potential double recovery of costs.

12 **Q. Do you have any other recommendations related to the LFCR?**

13 A. Yes. I recommend the Commission require an earnings test as a condition of receiving  
14 LFCR revenue in the future. An earnings test would require APS to submit documentation  
15 of actual versus authorized revenues for the year in question. If APS earned its authorized  
16 revenues, the Company should not be allowed to recover any LFCR revenues until it makes  
17 a showing that revenues are deficient. An earnings test would protect APS ratepayers from  
18 over recovery of revenues, which has been an issue in recent years.

19 **Q. Are you aware of examples of other utilities or commissions that use an earnings**  
20 **test?**

21 A. Yes. New Jersey Natural Gas is subject to an earnings test on an annual basis to recover  
22 lost revenues through its Conservation Incentive Program filing. The Company must show  
23 that it did not earn more than its rate of return on common equity to recover lost revenues  
24 from its energy efficiency programs.<sup>71</sup>

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<sup>70</sup> See Exhibit BJB-10 APS Response to SWEEP DR 1.19.

<sup>71</sup> In The Matter Of The Petition Of New Jersey Natural Gas Company For The Annual Review And Revision Of Its Basic Gas Supply Service (BGSS) And Conservation Incentive Program (CIP) Rates For F/Y 2021. Docket No. GR20060378. May 29, 2020. [njng.com/regulatory/pdf/NJNG-2021-Annual-BGSS-and-CIP-Filing-transmittal.pdf](https://www.njng.com/regulatory/pdf/NJNG-2021-Annual-BGSS-and-CIP-Filing-transmittal.pdf)

## **VIII. THE COMMISSION SHOULD CONSIDER A PBR FRAMEWORK FOR APS.**

**Q. Please describe the recent trends driving the need for regulatory reform in Arizona.**

A. There are several key trends that are driving the need for regulatory reform in Arizona. Recent growth in customer-sited rooftop solar coupled with declining volumetric sales driven by energy efficiency have presented revenue recovery issues for utilities. The revenue recovery concerns have led utilities to propose rate design focused more on revenue recovery than cost causation. These approaches have limited customer control of bills. Finally, APS has faced considerable customer service issues resulting from its failed rollout of new rate designs from its last rate case.

A recommendation to consider performance-based ratemaking is mainly driven by the need for regulatory reform in Arizona. Arizona currently relies on a utility business model approach that is outdated and in need of significant updating. The current model is based on utilities recovering cost of service with a fair return. It incentivizes utilities to promote sales growth and grow rate base through capital additions, while not focusing on the value of service to customers. The current business model is also heavily focused on revenue recovery, which has driven utilities to request rate design options that are not in the best interests of customers or based on cost causation.

**Q. Why is PBR suitable for APS at this time?**

A. In addition to the points made above related to the general need for regulatory reform in Arizona, APS customer satisfaction is very low.<sup>72</sup> Customer complaints following the implementation of APS's new rate plans were significantly high, as were the number of defaults and late payments for residential customers. APS's earnings should be motivated by customer satisfaction, not revenue recovery.

**Q. What is PBR?**

A. PBR is a regulatory approach that aligns revenues and utility earnings with performance goals and metrics. The general objective of this approach is to move away from simple cost of service ratemaking that drives electric utilities towards large capital investments and increasing volumetric sales to maximize revenue to revenue opportunities that maximize

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<sup>72</sup> J.D. Power. 2019. Electric Utility Residential Customer Satisfaction Study. [jdpower.com/business/press-releases/2019-electric-utility-residential-customer-satisfaction-study](https://www.jdpower.com/business/press-releases/2019-electric-utility-residential-customer-satisfaction-study)

1 value for customers. Technology has changed significantly since the early days of utility  
2 regulation and approaches to revenue recovery should also change.

3 There are many ways to approach PBR, ranging from simple (performance  
4 incentives on energy efficiency) to complex (formula rate plans layered with numerous  
5 quantified performance metrics). The approach should focus on the jurisdictional  
6 regulatory goals and be reviewed and updated to refine the policy based on experience.

7 **Q. Is APS already engaged in PBR?**

8 A. Yes, somewhat. The ACC approved the current APS demand side management  
9 performance incentive under Decision No. 77763.<sup>73</sup> The current incentive structure allows  
10 APS to earn up to 8% of the total net benefits of the program but is capped at \$0.0125/kWh  
11 saved. The performance incentive does not require APS to meet any specific savings targets  
12 or other program related goals. While this incentive likely drives APS to deliver energy  
13 savings with higher net benefits, it could be much improved and provide additional  
14 financial incentives tied to APS meeting additional policy goals.

15 **Q. Are other states engaged in PBR?**

16 A. Yes. While not a new concept or idea, interest in PBR has grown in recent years. Several  
17 key trends, including declining and flattening volumetric sales, growth of distributed  
18 generation, and the proliferation of new energy technologies, continue to threaten the  
19 traditional utility business model. While many states have implemented PBR-like  
20 performance incentives for various aspects of utility business operations (including this  
21 Commission), several states have explored implementing PBR. These states include  
22 Illinois, Massachusetts, New York, Minnesota, and Hawaii. I will expand on Illinois,  
23 Hawaii, Minnesota, and Massachusetts below.

24 **d. Illinois**

25 **Q. Please provide detail on the Illinois PBR framework.**

26 A. In October 2011, the Illinois General Assembly passed the Energy Infrastructure  
27 Modernization Act. The law addressed infrastructure modernization, but also focused on  
28 regulatory reform and the establishment of performance metrics. The bedrock of the  
29 regulatory reforms was the development of performance-based formula rates. Formula

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<sup>73</sup> Arizona Corporate Commission. Decision No. 77763. October 2, 2020. Docket No. E-01345A-19-0088.

1 rates are not a new concept but have generally been used by FERC where financial returns  
2 have not been tied to performance.

3 The performance-based formula rate is optional for utilities in Illinois and only  
4 covers distribution related costs. The law required participating utilities to make  
5 investments in infrastructure and customer assistance designed to reduce costs for  
6 customers. ComEd and Ameren, the two largest utilities in the state, both elected to  
7 participate and have made substantial modernization investments since 2011.

8 The formula rate process relies on forecasted costs and billing determinants to set  
9 rates, but then reconciles rates based on actual costs and sales. The formula resets rates  
10 annually, with an annual reconciliation as well. Both parts of this process, the establishment  
11 of rates using forecasted data and reconciling rates based on actual costs and sales, undergo  
12 regulatory review in a docketed case process.

13 **Q. Please describe the performance-based aspect of the formula rate in Illinois.**

14 A. For ComEd, the performance-based aspect of this approach comes in the form of a return  
15 on equity (“ROE”) penalty if ComEd does not meet specific performance metrics.<sup>74</sup> There  
16 are no ROE rewards or bonuses for meeting the performance metric goals below, only the  
17 potential penalties. The penalties cannot exceed a 50-basis point adjustment. The metrics  
18 fall under the following general categories:

19 1. Reliability

20 a. System Average Interruption Frequency Index (“SAIFI”) and  
21 Consumer Average Interruption Duration Index (“CAIDI”) targets  
22 based on reducing the frequency and duration of outages over a ten-year  
23 period with annual targets.

24 b. Service reliability targets

25 i. Customers whose immediate primary source of service operates  
26 at 69,000 volts or above should not have experienced: i) More  
27 than three controllable interruptions in each of the last three  
28 consecutive years. ii) More than nine hours of total interruption

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<sup>74</sup> For more information on the ComEd performance metrics, see *Commonwealth Edison Company’s Multi-Year Performance Metrics Annual Report for the Year Ending December 31, 2018*. April 8, 2019. Filed in Docket No. 11-0772, Illinois Commerce Commission.

1 duration due to controllable interruptions in each of the last three  
2 consecutive years.

3 ii. Customers whose immediate primary source of service operates  
4 at more than 15,000 volts, but less than 69,000 volts, should not  
5 have experienced: i) More than four controllable interruptions in  
6 each of the last three consecutive years. ii) More than twelve  
7 hours of total interruption duration due to controllable  
8 interruptions in each of the last three consecutive years.

9 iii. Customers whose immediate primary source of service operates  
10 at 15,000 volts or below should not have experienced: i) More  
11 than six controllable interruptions in each of the last three  
12 consecutive years. ii) More than eighteen hours of total  
13 interruption duration due to controllable interruptions in each of  
14 the last three consecutive years.

15 2. Minority-Owned and Women-Owned Business Enterprises (“MWBE”)

16 a. Goal to increase its capital expenditures paid to MWBE by 15% over  
17 the 10-year period.

18 3. Advanced Metering Infrastructure Related Metrics

19 a. Reducing the number of estimated electric bills by 90% over a ten-year  
20 period.

21 b. Reduce consumption on inactive meters by 90% ratably over a ten-year  
22 period.

23 c. Reduce unaccounted for energy by 50% ratably over a ten-year period.

24 d. Reduce uncollectible expense by \$30,000,000 ratably over a ten-year  
25 period.

26 e. Aggregate average percent to goal on Consumption on Inactive Meters,  
27 Unaccounted for Energy, and Uncollectible Expense.

1 **Q. Does Illinois also have a performance incentive or penalty for energy efficiency**  
2 **performance?**

3 A. Yes. Public Act 99-0906, also known as the Future Energy Jobs Act, was enacted in 2016.<sup>75</sup>  
4 This law created energy efficiency savings goals, outlined cost recovery methods, and  
5 provided a performance incentive/penalty structure for participating utilities. Utilities have  
6 an opportunity to earn a reward or face a penalty based on meeting energy efficiency  
7 savings targets. The penalties and awards vary based on the size of the utility and the year  
8 of performance.

9 **Q. What have the results been in Illinois under PBR?**

10 A. Ameren Illinois and ComEd both elected to participate in the formula rate structure allowed  
11 under the Energy Infrastructure Modernization Act. According to a recent report by the  
12 Illinois Commerce Commission (“ICC”), both utilities are on track to meet the investment  
13 requirements under the Act. In 2017, the ICC reported that ComEd’s residential customers  
14 saw a decrease in rates between 2011 and 2017 (-0.0922% compounded annual growth  
15 rate) while Ameren residential customer saw a modest increase during this time period  
16 (1.68% annual compound growth rate).<sup>76</sup>

17 In a 2017 annual report, ComEd boasted significant reliability benefits and  
18 customer savings created through the grid modernization efforts, claiming \$1.4 billion in  
19 societal savings produced through avoided outages.<sup>77</sup>

#### 20 **e. Massachusetts**

21 **Q. Please provide background on the PBR efforts in Massachusetts.**

22 A. In 2017 the Massachusetts Department of Public Utilities (“DPU”) approved PBR for  
23 Eversource through its rate case.<sup>78</sup> Eversource already utilized a decoupling mechanism to  
24 ensure collection of DPU authorized revenues, but was experiencing a loss of sales growth

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<sup>75</sup> For more on the details of the performance incentive/penalty structure, please see Illinois 220-ILCS 5/ Public Utilities Act.

[ilga.gov/legislation/ilcs/ilcs4.asp?ActID=1277&ChapterID=23&SeqStart=35100000&SeqEnd=39400000](http://ilga.gov/legislation/ilcs/ilcs4.asp?ActID=1277&ChapterID=23&SeqStart=35100000&SeqEnd=39400000)

<sup>76</sup> Report on the Energy Infrastructure Modernization Act’s Infrastructure Program and Performance Based Formula Rate Plan. Illinois Commerce Commission. December 2017.

[icc.illinois.gov/downloads/public/ga/Energy%20Infrastructure%20Modernization%20Act%20Report%20Dec%202017.pdf](http://icc.illinois.gov/downloads/public/ga/Energy%20Infrastructure%20Modernization%20Act%20Report%20Dec%202017.pdf)

<sup>77</sup> Five Year Capstone Report, Commonwealth Edison Company. 2017.

[comed.com/SiteCollectionDocuments/AboutUs/ComEdProgressReport2017.pdf](http://comed.com/SiteCollectionDocuments/AboutUs/ComEdProgressReport2017.pdf)

<sup>78</sup> See Order Establishing Revenue Requirement for NSTAR Electric Company and Western Massachusetts Electric Company (each doing business as Eversource Energy). Massachusetts Department of Public Utilities.

[eversource.com/content/docs/default-source/investors/d-p-u-17-05-final-order-\(revenue-requirement\)-11-30-17.pdf](http://eversource.com/content/docs/default-source/investors/d-p-u-17-05-final-order-(revenue-requirement)-11-30-17.pdf)

1 between rate cases that had previously allowed the Company to fund ongoing capital  
2 investments. Intervenor in the rate case argued that a capital cost recovery mechanism  
3 would be an appropriate substitute for PBR, but the DPU disagreed, citing the  
4 administrative burden of frequent rate cases and review of the capital recovery mechanism.  
5 DPU also stated that the PBR mechanism will allow greater incentives to meet various state  
6 policy goals.

7 The DPU approved the PBR formula rate plan for a five-year term and stay-out  
8 provision (Eversource will not file a rate case) unless its actual ROE falls more than 200  
9 basis points below the approved ROE.

10 The DPU did not adopt new performance incentive metrics for the Eversource PBR  
11 plan. Instead, the existing service quality metrics would continue to be assessed, with  
12 penalties for inability to meet these metrics. However, the DPU did establish a process to  
13 adopt final metrics and benchmarks for additional performance metrics related to the PBR  
14 plan. As part of this process, DPU directed Eversource to develop metrics focused on:

- 15 1. Level of customer satisfaction and engagement;
- 16 2. Reductions in peak demand; and
- 17 3. Progress towards climate adaptation and greenhouse gas reductions.

#### 18 **f. Minnesota**

19 **Q. Please provide background on the PBR efforts in Minnesota.**

20 A. The Minnesota Public Utilities Commission (“MNPUC”) is currently examining  
21 performance-based regulation for Xcel Energy, the state’s largest electric utility.<sup>79</sup> The  
22 development of performance metrics was required after Xcel Energy proposed a multiyear  
23 rate plan in 2016.<sup>80</sup> The goal of this process is to establish performance metrics for Xcel  
24 Energy, which may ultimately lead to financial incentives. The process is still ongoing, and  
25 stakeholders are working together to answer many critical questions about the performance  
26 metrics. The process is divided into two distinct phases, the first to establish metrics and  
27 the second is to determine how they will be calculated. The development of metrics is  
28 focused on meeting five MNPUC defined outcomes of the process. These five outcomes  
29 include:

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<sup>79</sup> See Docket No. E-002/CI-17-401.

<sup>80</sup> Minn. Stat. § 216B.16, subd. 19.

1. Affordability;
2. Reliability, including both customer and system-wide perspectives;
3. Customer service quality, including satisfaction, engagement and empowerment;
4. Environmental performance, including carbon reductions and beneficial electrification; and
5. Cost effective alignment of generation and load, including demand response.

In September 2019, the MNPUC adopted a series of performance metrics for Xcel Energy.<sup>81</sup> These metrics include:

1. Affordability – average monthly bills, revenue per kWh, total arrearages, and total disconnections for nonpayment;
2. Reliability - SAIDI, SAIFI, CAIDI, CELID, CEMI, and ASAI;
3. Customer Service Quality – JD Power customer satisfaction score, call-center response time, billing invoice accuracy, and number of customer complaints;
4. Environmental Performance – total carbon emissions, carbon intensity, total criteria pollutant emissions, total criteria pollutant intensity, additional metrics measuring the impact of electrification in other sectors, including transportation, agricultural, and buildings; and
5. Cost Effective Alignment of Generation and Load – demand response capacity available and called, metrics measuring the amount of demand response that (i) shapes customer load profiles through price response, time-varying rates, or behavior campaigns, (ii) shifts energy consumption from times of high demand to times when there is a surplus of renewable generation, and (iii) sheds loads that can be curtailed to provide peak capacity and support the system in contingency events.

This list is not exhaustive but is intended to present a summary of most of the metrics adopted by the MNPUC. The Commission also directed stakeholders to develop several “future” metrics focused in specific areas of interest. The second phase of the proceeding,

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<sup>81</sup> See Order Establishing Performance Metrics, In the Matter of a Commission Investigation to Identify Performance Metrics, and Potentially, Incentives for Xcel Energy’s Electric Utility Operation. September 18, 2019. Docket No. E-002/CI-17-401. Minnesota Public Utilities Commission.

1 to determine how to measure and track the approved metrics, is currently underway and  
2 expected to be completed in 2020.

3 **g. Hawaii**

4 **Q. Please provide background on the PBR efforts in Hawaii.**

5 A. In 2018, the Hawaii Public Utilities Commission (“HIPUC”) opened a proceeding into  
6 PBR. Hawaii had recently adopted a 100% renewable energy goal by 2045 and customer  
7 behavior and technology adoption have been rapidly changing there. The proceeding will  
8 occur over multiple phases. The first phase was intended to identify core elements of the  
9 PBR framework and direct the development of key details in the second phase.<sup>82</sup> The  
10 second phase will focus on the design and implementation of regulatory mechanisms to  
11 achieve the goals outlined in Phase 1. Hawaii’s process is holistic, including a focus on  
12 revenue mechanisms and performance metrics.

13 The Phase 1 process produced a series of principles and goals for the Phase 2  
14 process. The three guiding principles include:<sup>83</sup>

- 15 1. A customer-centric approach. A PBR framework should encourage the  
16 expanding opportunities for customer choice and participation in all appropriate  
17 aspects of utility system functions, including verifiable “day-one” savings for  
18 customers.
- 19 2. Administrative efficiency. PBR offers an opportunity to simplify the regulatory  
20 framework and enhance overall administrative efficiency.
- 21 3. Utility financial integrity. The financial integrity of the utility is essential to its  
22 basic obligation to provide safe and reliable electric service for its customers  
23 and a PBR framework is intended to preserve the utility’s opportunity to earn a  
24 fair return on its business and investments, while maintaining attractive utility  
25 features, such as access to low-cost capital.

26 The regulatory goals are focused on enhancing customer experience, improving  
27 utility performance, and advancing social outcomes. Through the Phase 1 process, the  
28 HIPUC also directed the development of priority revenue adjustment mechanisms in Phase

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<sup>82</sup> See Decision and Order No. 36326. Public Utilities Commission of Hawaii. Instituting a Proceeding to Investigate Performance Based Regulation. Docket No. 2018-0088. May 23, 2019.

<sup>83</sup> Order at 6.

2, including multiyear formula rate plans and earnings sharing mechanisms, and priority performance mechanisms, including performance incentive mechanisms, shared savings mechanisms, and scorecards and reported metrics. Phase 2 is currently underway and expected to be completed in late 2020.

#### **h. PBR Conclusions**

**Q. Please summarize your takeaways from these examples as they relate to APS's current rate case.**

A. These examples provide background information and source documents on the approaches utilized in these states. PBR is generally made up of two parts, a formula rate or revenue recovery mechanism and a performance incentive mechanism. The formula rate allows a utility to recover prudently incurred costs in a timely manner. Customers are protected from overearning because revenues are reconciled with actual costs and sales, meaning customers are only charged for costs that are actually incurred. Formula rates, through well-defined protocols, also can reduce rate case expense and litigation that typically comes with traditional rate cases. APS has discussed a formula rate in this case but has not proposed a specific mechanism for consideration.

These examples illustrate several states that are currently grappling with the need for regulatory reform. These states face many of the same issues Arizona is facing today, especially the need to update the traditional utility business model that rewards capital expenditures and promotes sales growth.

**Q. What are some performance metrics the ACC could consider in a PBR approach for APS?**

A. There are many metrics the ACC could consider when approaching PBR for APS. However, these metrics should be carefully considered. They should be quantifiable, within the utility's control, and easily understood by all stakeholders. The primary purpose of establishing financial incentives for meeting performance metrics is to motivate a utility to behavior that would not occur absent the incentives. A utility should not be given financial incentives for things it would have done in the absence of the incentives. Some metrics may include:

1. Reliability – reducing the frequency and duration of outages;
2. Customer Service – improving customer satisfaction during customer calls, reducing customer complaints, and improving billing accuracy;

3. Safety – reducing Company work related accidents;
4. Energy Efficiency – exceeding energy savings goals and achieving other quantifiable performance metrics driven by state policy goals;
5. Renewable Energy – increasing the renewable energy percentage of generation portfolio beyond statutorily required levels;
6. Emissions reductions – reducing CO<sub>2</sub> emissions, specifically those related to generation (including owned generation, purchase power agreements, and market purchases);
7. TOU Rates – increasing the numbers of customers on time of use rates, which drive many benefits to customers;
8. Peak Demand Reduction – reducing local and system peaks;
9. Delinquent Accounts – reducing the number of delinquent accounts and bad debt expense driven by nonpayment of bills. This can be done by giving customers tools to manage bills, like energy efficiency measures; and
10. EV Programs – increasing the number of charging stations installed, number of customers subscribed to EV TOU rates, and performance of managed charging programs.

**Q. How do you recommend the Commission proceed?**

A. In February of this year, Commissioner Márquez Peterson opened a docket to investigate the role of performance incentive mechanisms in Arizona rate cases. I recommend the Commission initiate a workshop in that docket to begin a statewide discussion of PBR in Arizona. While not necessarily required, a multiyear formula rate plan should also be considered in combination with a series of performance metrics to align APS' financial interests with societal goals. The benefits of this approach are significant, but it will require substantial resources to develop an effective approach. Decoupling is discussed previously in my testimony as another approach to address APS's revenue recovery issues while aligning the Company's interests with its customers. A decoupling mechanism should be considered as a near term solution to the problems facing APS but is less desirable than a multiyear formula rate plan.

1       **IX. CONCLUSION**

2       **Q. Please summarize your recommendations to the Commission in this case.**

3       A. I recommend the following:

- 4           1. The Commission should freeze all residential three-part rates to new customer  
5           enrollment and discontinue these rates options.
- 6           2. The Commission should deny APS' request to increase the BSC for residential and  
7           general service customers and set the BSC at \$8.03 for all residential rates.
- 8           3. The Commission should require APS to shorten the TOU on-peak window to three  
9           hours from 4 p.m. to 7 to improve customer response and to better align with current  
10          APS customer consumption patterns and cost of service.
- 11          4. The Commission should require APS to default all new APS residential customers to  
12          TOU rates.
- 13          5. The Commission should order APS to restructure residential EV rates to provide price  
14          signals that encourage off-peak charging by providing a night super off-peak period to  
15          winter and summer months.
- 16          6. The Commission should order APS to recover \$65 million of energy efficiency  
17          program costs in base rates.
- 18          7. The Commission should allow APS to book energy efficiency program costs as a  
19          regulatory asset, amortize these costs over a seven-year period, and earn a return on  
20          these investments.
- 21          8. The Commission should reject the APS proposal to keep some costs in the LFCR and  
22          should reset the adjustor to zero.
- 23          9. The Commission should require APS to submit documentation of actual lost revenue  
24          through an earnings test in order to collect any revenue through the LFCR.
- 25          10. The Commission should reject the APS proposal to conduct a subscription pricing pilot.
- 26          11. The Commission should initiate the already opened statewide generic investigation into  
27          PBR to improve utility business models in Arizona by allowing utilities revenue  
28          opportunities to meet specific performance metrics and goals.

29       **Q. Does this complete your direct testimony?**

30       A. Yes.

# **EXHIBIT BJB - 1**

## **Professional Experience**

Gabel Associates Inc.

Highland Park, NJ

Vice President

2018-Present

- Support and advise clients on a variety of energy and regulatory issues including retail and wholesale electric rate design, energy efficiency policy and program design, cost benefit analysis, resource planning, and renewable energy project development.
- Lead consultant to the solar industry in New York Reforming the Energy Vision (REV) regulatory process on rate design for mass market customers.
- Provide ongoing consulting services to multiple gas and electric utilities on energy efficiency program design, cost benefit analysis, avoided cost development, strategic guidance, and program delivery in New Jersey.
- Advise various wholesale energy market clients, including power plant project developers and operators on regulatory issues such as retail ratemaking, wholesale ratemaking, RTO governance, FERC rulemakings, and other relevant issues.
- Provide technical expert testimony for various clients in regulatory matters before state energy commissions. Have testified in Arizona, Colorado, Indiana, Maryland, New Jersey, New York, Oklahoma, Pennsylvania, and Washington D.C

American Council for an Energy-Efficient Economy

Washington, D.C.

Senior Manager, Utilities Program

2014-2018

- Oversaw and coordinated ACEEE's efforts related to utility sector energy efficiency programs. Served as project manager and lead author for research projects involving utility sector energy efficiency programs, business models, best practices, rate design, and other topics.
- Provided technical assistance for utilities and other energy efficiency implementation partners such as state government agencies on a variety of regulatory policy and best practice program topics.
- Filed testimony and formal comments before state regulatory commissions on issues related to energy efficiency programs, integrated resource planning, rate design, and other issues related to the best practices and policies for implementing energy efficiency.

Federal Energy Regulatory Commission

Washington, D.C.

Energy Industry Analyst

2013-2014

- Served as a technical expert in litigated cases before the Federal Energy Regulatory Commission on behalf of the FERC trial staff. Issues examined included: wholesale energy rates, transmission rates, Open Access Transmission Tariff interpretation, transmission capacity rights, cost allocation for various customer classes, formula rate mechanics and protocols, electric cost of service, interruptible load, rate design, and regional transmission organization functionality and governance.

Maryland Public Service Commission  
Energy Analyst

Baltimore, MD  
2012–2013

- Reviewed and analyzed utility filings for EmPOWER Maryland statewide energy efficiency, conservation, and demand response programs. Presented results of research before the Commission. Worked closely with the Agency energy efficiency evaluation contractor to develop evaluation policies that reduced costs for Maryland ratepayers while ensuring integrity of the evaluation process.

Indiana Office of Utility Consumer Counselor  
Utility Analyst

Indianapolis, IN  
2011–2012

- Served as a technical expert witness in utility cases before the Indiana Utility Regulatory Commission on behalf of utility ratepayers in the State of Indiana. Developed agency position through analyses of relevant utility applications, petitions, testimony, schedules, and exhibits. Served as agency representative in collaborative demand side management oversight boards for electric and gas utilities.

## Education

Master of Public Affairs, Environmental Policy Analysis, Indiana University Bloomington, 2010

BS, Political Science and Sociology, Arizona State University, 2007

## Selected Research Publications

B. Baatz, G. Relf, and S. Nowak. 2018. The Role of Energy Efficiency in a Distributed Energy Future. *The Electricity Journal*, Vol. 31, Issue 10. doi.org/10.1016/j.tej.2018.11.004.

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B. Baatz and A. Gilleo. 2016. Big Savers: Experiences and Recent History of Program Administrators Achieving High Levels of Electric Savings. *The Electricity Journal*, Vol. 29, Issue 8. doi.org/10.1016/j.tej.2016.09.009.

B. Baatz. 2015. Everyone Benefits: Practices and Recommendations for Utility System Benefits of Energy Efficiency. Washington, DC: ACEEE. [aceee.org/everyone-benefits-practices-and-recommendations](http://aceee.org/everyone-benefits-practices-and-recommendations).

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## **Selected Expert Witness Regulatory Cases**

Atlantic City Electric Company; New Jersey Board of Public Utilities; September 25, 2020 (Docket No. QO10010040). Client: Atlantic City Electric Company. Issue: cost benefit analysis and program design support for three-year energy efficiency plan.

New Jersey Natural Gas Company; New Jersey Board of Public Utilities; September 25, 2020 (Docket No. GO20090622). Client: New Jersey Natural Gas Company. Issue: cost benefit analysis for three-year energy efficiency filing.

Jersey Central Power and Light; New Jersey Board of Public Utilities; September 25, 2020 (Docket No. EO20090620). Client: Jersey Central Power and Light. Issue: cost benefit analysis for three-year energy efficiency filing.

Elizabethtown Gas; New Jersey Board of Public Utilities; July 31, 2020 (Docket No. GR20070503). Client: Elizabethtown Gas. Issues: cost benefit analysis for energy efficiency true up filing.

Tucson Electric Power Company; Arizona Corporate Commission (Docket No. E- 01933A-19-0028); October 11, 2019. Client: Southwest Energy Efficiency Partnerships Issues: performance-based ratemaking, energy efficiency program cost recovery, time of use rate design, electric vehicle rate design.

Black Hills Colorado Electric; Public Utilities Commission of Colorado (Proceeding No. 18A-0676E), January 22, 2019. Client: Pueblo County, Colorado. Issue: time of use pilot proposal, low income bill analysis.

Oklahoma Gas and Electric Company; Oklahoma Corporate Commission (Cause No. PUD 201800140); April 22, 2019. Client: Oklahoma Energy Results. Issues: prudence of environmental cost recovery for aged coal units, integrated resource planning assessment.

Lancaster Solid Waste Management Authority; Federal Energy Regulatory Commission (Docket No. ER19-342); November 14, 2018. Client: Lancaster Solid Waste Management Authority. Issue: reactive power ratemaking.

Elizabethtown Gas; New Jersey Board of Public Utilities (Docket No. GR18080860); August 8, 2018. Client: Elizabethtown Gas. Issues: cost benefit analysis for energy efficiency true up filing.

Duquesne Light Company; Pennsylvania Public Utility Commission (Docket R-2018-3000124); June 25, 2018. Client: Keystone Energy Efficiency Alliance, Natural Resources Defense Council, and Clean Air Council. Issues: submetering for multifamily buildings, time of use rates, rate design.

Tucson Electric Power Company; Arizona Corporate Commission (Docket No. E- 01933A-15-0322); June 24, 2016. Client: Southwest Energy Efficiency Partnerships Issues: rate design, prepaid electricity.

PECO Electric Company; Pennsylvania Public Utility Commission (Docket R-2015-2468981); June 23, 2015. Client: Keystone Energy Efficiency Alliance, Natural Resources Defense Council, and Clean Air Council. Issues: rate design, revenue decoupling.

PPL Electric Corporation; Pennsylvania Public Utility Commission (Docket R-2015-2469275); June 23, 2015. Client: Keystone Energy Efficiency Alliance, Natural Resources Defense Council, and Clean Air Council. Issues: rate design, revenue decoupling.

Northern Indiana Public Service Company; Indiana Utility Regulatory Commission (Cause 44012); October 20, 2011. Representing Indiana Office of Utility Consumer Counselor. Issues: environmental control upgrades, alternate scenario economic analysis.

Indianapolis Power and Light Company; Indiana Utility Regulatory Commission (Cause 43623 DSM-5); April 26, 2012. Representing Indiana Office of Utility Consumer Counselor. Issue: energy efficiency performance incentive reconciliation.

Indianapolis Power and Light Company; Indiana Utility Regulatory Commission (Cause 44018); August 22, 2011. Representing Indiana Office of Utility Consumer Counselor. Issue: renewable energy feed in tariff design.

Indiana Michigan Power Company; Indiana Utility Regulatory Commission (Cause 44034); August 12, 2011. Representing Indiana Office of Utility Consumer Counselor. Issue: renewable energy credit benefit allocation.

Indiana Gas Company, Inc. and Indiana Gas and Electric Company; Indiana Utility Regulatory Commission (Cause 44019); May 20, 2011. Representing Indiana Office of Utility Consumer Counselor. Issue: revenue decoupling.

# **EXHIBIT BJB - 2**

SOUTHWEST ENERGY EFFICIENCY PROJECT'S  
SECOND SET OF DATA REQUESTS TO  
ARIZONA PUBLIC SERVICE COMPANY REGARDING  
THE APPLICATION TO APPROVE RATE SCHEDULES DESIGNED TO  
DEVELOP A JUST AND REASONABLE RATE OF RETURN  
DOCKET NO. E-01345A-19-0236  
JUNE 17, 2020

SWEEP 2.8: Referencing APS response to SWEEP 1.14, please provide the number of defaults and late payments by year for the previous seven (7) years for residential rate and small commercial rate plans. The seven-year period should include 2011 through 2018 as APS has already provided this data for 2019.

Response: Please see attachment ExcelAPS19RC01420 for the number of defaults (service shut off for non-payment) and the number of late payments for both residential and small commercial rate plans for the years 2011-2018. The data for number of defaults at the customer level for 2011-2013 is unavailable.

Witness: TBD

Response to SWEEP 2.8

<b># of Defaults</b>	2018	2017	2016	2015	2014	2013	2012	2011
Residential	105,206	55,303	85,433	75,014	67,021			
Small Commercial	4,755	434	2,737	2,742	2,624			

<b># of Late Payments</b>	2018	2017	2016	2015	2014	2013	2012	2011
Residential	1,640,500	1,595,102	1,113,755	1,156,336	1,121,093	1,073,333	1,144,226	1,243,211
Small Commercial	112,129	110,766	57,138	57,073	54,368	52,725	57,373	65,155

**EXHIBIT BJB – 3**  
**HIGHLY CONFIDENTIAL**

**EXHIBIT BJB – 4**  
**HIGHLY CONFIDENTIAL**

# **EXHIBIT BJB – 5**

SOLAR ENERGY INDUSTRIES ASSOCIATION'S  
THIRD SET OF DATA REQUESTS TO  
ARIZONA PUBLIC SERVICE COMPANY REGARDING  
THE APPLICATION TO APPROVE RATE SCHEDULES DESIGNED TO  
DEVELOP A JUST AND REASONABLE RATE OF RETURN  
DOCKET NO. E-01345A-19-0236  
JANUARY 30, 2020

SEIA 3.11: Please provide the hourly non-solar residential retail system load for 2016, 2017, 2018, and 2019. This request is for all residential customers that do not have solar, regardless of their rate class.

Response: Please see attachment ExcelAPS19RC00386 for January 2016 through June of 2019. Hourly non-solar residential retail system load for July through December of 2019 is not currently available and will be provided as soon as it is complete.

Witness: Leland Snook

# **EXHIBIT BJB – 6**

SOLAR ENERGY INDUSTRIES ASSOCIATION'S  
THIRD SET OF DATA REQUESTS TO  
ARIZONA PUBLIC SERVICE COMPANY REGARDING  
THE APPLICATION TO APPROVE RATE SCHEDULES DESIGNED TO  
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DOCKET NO. E-01345A-19-0236  
JANUARY 30, 2020

SEIA 3.10: Please refer to the Company's response to RUCO 2.1.

- a. Confirm whether the data represents the gross system load (that is, before any load that is met through on-site solar) or the net system load (that is, after any load is met through on-site solar).
- b. Please provide the hourly retail system load for 2016 and 2019 containing the same data as was provided in RUCO 2.1.
- c. Please provide the hourly retail system load for 2016, 2017, 2018, and 2019 that contains the either the gross system load (if RUCO 2.1 contains the net system load) or the net system load (if RUCO 2.1 contains the gross system load).

Response:

- a. The data included in RUCO 2.1 is net system load.
- b. The hourly retail system load for 2016 is included in attachment ExcelAPS19RC00384. January through June of 2019 was provided in response to RUCO 2.1. The hourly retail system load for July through December of 2019 is not currently available, but will be provided when complete.
- c. The gross system retail load is included in ExcelAPS19RC00385 for January of 2016 through June of 2019. The hourly retail system load for July through December of 2019 is not currently available, but will be provided when complete.

Witness: Leland Snook

# **EXHIBIT BJB – 7**

## Arizona Public Service BSC Calculation

<b>Electric Customer-Related Costs for Arizona Public Service</b>		
<b>Expenses</b>	<b>Account</b>	<b>Residential</b>
Meters	597	\$ -
	586	\$ 7,846,726
	Depreciation	\$ 19,883,243
Services	587	\$ 8,054
	Depreciation	\$ 8,784,347
Meter Reading	902	\$ 1,835,313
Billing	903	\$ 36,397,367
Subtotal Expenses		\$ 74,755,050
Net to Gross on Expenses		100.00%
Total Expenses		\$ 74,755,050
<b>Rate Base</b>		
Meters		
Plant In Service	370	\$ 260,818,873
Less Accumulated Depreciation		\$ (215,013,203)
Net Plant		\$ 45,805,670
Depreciation Expense		\$ 19,883,243
Services		
Plant In Service	369	\$ 375,419,614
Less Accumulated Depreciation		\$ (108,285,589)
Net Plant		\$ 267,134,025
Depreciation Expense		\$ 8,784,347
Meters		\$ 45,805,670
Services		\$ 267,134,025
Total Rate Base		\$ 312,939,695
Grossed Up Return (10.15 ROE)	8.02%	\$ 25,094,719
<b>Total Customer-Related Revenue Requirement</b>		<b>\$ 99,849,769</b>
<b>Annual Bills</b>		12,429,432
<b>\$/Month</b>		<b>\$ 8.03</b>

Raw data by account from Schedules A through H and LRS\_WP2DR

# **EXHIBIT BJB – 8**

SOUTHWEST ENERGY EFFICIENCY PROJECT'S  
SECOND SET OF DATA REQUESTS TO  
ARIZONA PUBLIC SERVICE COMPANY REGARDING  
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DOCKET NO. E-01345A-19-0236  
JUNE 17, 2020

**SWEEP 2.2:** Please provide all measure level assumptions for all measures included in the most recently filed DSM plan. For each measure, please include the following information:

- a. first year energy savings (kWh)
- b. first year demand savings (kW)
- c. savings decay or degradation factor (if APS does not assume a savings decay, please explain why not)
- d. incremental measure cost (\$)
- e. baseline assumption
- f. installation cost (\$)
- g. net to gross assumption
- h. measure lifetime (years)

**Response:** APS is still compiling the information for this response, and will provide it as soon as it is available.

**Supplemental Response:**

- a. Please see the attached spreadsheet ExcelAPS19RC01475.
- b. Please see the attached spreadsheet ExcelAPS19RC01475.
- c. APS does not assume a savings decay factor. The Company's "measure lifetime assumptions" account for the average persistence of savings when in some cases the savings persist longer or shorter. The savings from most measures does not significantly decay over time, and the rate of decay is also difficult to predict in most cases due to many unknown factors such as frequency of equipment maintenance over time. The cost of collecting such data outweighs the benefit and adds a layer of false precision when coupled with the other inputs used to calculate cost-effectiveness including - measure life, avoided costs, incremental costs, energy and demand savings, and net-to-gross assumptions.
- d. Please see the attached spreadsheet ExcelAPS19RC01475.
- e. Please see the attached spreadsheet ExcelAPS19RC01475.
- f. The installation costs for each measure are included in the overall incremental costs that are provided in response to the Company's response to part d. These are not broken out separately because installation costs do not need to be separated out from the total incremental costs in cost

SOUTHWEST ENERGY EFFICIENCY PROJECT'S  
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DOCKET NO. E-01345A-19-0236  
JUNE 17, 2020

Response to  
SWEEP 2.2  
(continued):

effectiveness calculations.

- g. APS assumes a net to gross of 1.0 for all measures based on previous APS research showing that spillover and market influence created by DSM programs balances out free-ridership.
- h. Please see the attached spreadsheet ExcelAPS19RC01475.

# **EXHIBIT BJB – 9**

SOUTHWEST ENERGY EFFICIENCY PROJECT'S  
FIRST SET OF DATA REQUESTS TO  
ARIZONA PUBLIC SERVICE COMPANY REGARDING  
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DOCKET NO. E-01345A-19-0236  
FEBRUARY 28, 2020

SWEEP 1.23: Referencing Hobbick direct testimony page 7 at lines 12-15, please describe what is meant by "limited management of smart thermostat".

Response: Please see the Company's response to SEIA 1.10 subpart I. The Company will manage temperatures up to +/- 4 degrees, and the customer will be able to override the control at any time without penalty.

Witness: Jessica Hobbick

# **EXHIBIT BJB – 10**

SOUTHWEST ENERGY EFFICIENCY PROJECT'S  
FIRST SET OF DATA REQUESTS TO  
ARIZONA PUBLIC SERVICE COMPANY REGARDING  
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DOCKET NO. E-01345A-19-0236  
FEBRUARY 28, 2020

SWEEP 1.19: Please provide an explanation of why APS is not proposing to reset the lost revenue fixed cost recovery mechanism to zero.

Response: After APS's prior rate case, concerns were expressed over the delayed reset of the Lost Fixed Cost Recovery (LFCR) mechanism. Therefore, as part of this rate case, APS is proposing to leave the portion of the lost fixed costs presently collected in the LFCR mechanism, within that mechanism, rather than transferring it to base rates. This will ensure the estimated net bill impacts put forth in this rate case are what customers can expect on the rate effective date.

Witness: Leland Snook